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NOx Control Retrofit Study

Radian Corp., Research Triangle Park, NC

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ABSTRACT

This report documents the initial results from an ongoing program conducted under the National Acid Precipitation Assessment Program (NAPAP) by the U. S. EPA's Air and Energy Engineering Research Laboratory. The objective of this research program is to significantly improve engineering cost estimates currently being used to evaluate the economic effects of applying SO_2 controls to existing coal-fired utility boilers. A major factor affecting the cost and performance of SO_2 and NO_x controls for coal-fired power plants is the degree of difficulty associated with retrofitting controls at existing boilers. The objective of this research program is to significantly improve engineering cost estimates for the retrofit of the following control technologies at the 1980 top 200 SO_2 emitting coal-fired power plants in the 31 eastern states: lime/limestone FGD, lime spray drying FGD, coal switching and cleaning, furnace sorbent injection with humidification (LIMB), duct sorbent injection, low NO_x burners, over-fire air, natural gas reburn, and selective catalytic reduction.

This report documents the cost factors and costs developed for twelve coal-fired power plants--five in Ohio and seven in Kentucky and the Tennessee Valley Authority System (Tennessee, parts of Alabama, and Kentucky). The following activities were conducted to estimate the retrofit costs for the selected SO_2 and NO_x controls evaluated: selected plants with boilers representative to the population, conducted plant visits and collected site-specific data, developed boiler/control-specific retrofit difficulty factors, and developed boiler/plant-specific cost and performance estimates. The performance and cost estimating process is dynamic and incorporates recommendations from a technical advisory group and participating utilities, and experience from site visits and performance/cost evaluations. The information will be used to develop simplified procedures to estimate the retrofit costs of the remaining top 200 SO_2/NO_x emitting plants which are not visited. The cost and performance results presented in this report should be valuable to EPA, state agencies, and utility companies in evaluating cost-effective approaches for achieving SO_2 and NO_x emission reductions.

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LIST OF CONVERSION VALUES

CONVERSION TO METRIC VALUES

Btu/lb -- 2,325.445 Joules/Kg

Btu/hr -- 1054.8 Joules/hr

Btu/hr-ft^2 -- 13,273 cal/(sec)(sq cm)

Btu/kW-hr -- 3.9685 Kg cal/kW hr

feet (ft) -- 0.3048 m

ft^2/10^3 acfm -- 0.3048 m^2/actual m^3/sec

cu ft/min -- 0.028317 cu m/min

Kw -- 0.0011628 Kg-cal/hr

Kw-hr (kWh) -- 0.0011628 Kg-cal

mile -- 1.6093 Km

pound (lb) -- 0.45359 Kg

lb/MMBtu -- 0.0043 Kg/Joules

ton -- 907.18 Kg

1. INTRODUCTION

The National Acid Precipitation Assessment Program (NAPAP) is responsible for developing cost and performance information on various methods for reducing the emissions of acid rain precursors. Coal-fired utility boilers are major emitters of SO_2 and NO_x. However, estimating the cost and performance of SO_2 and NO_x controls for coal-fired power plants is difficult due to differences in plant layout and boiler design.

This report documents the initial results of an ongoing study conducted under NAPAP by the United States Environmental Protection Agency's Air and Energy Engineering Research Laboratory. The objective of this study is to significantly improve the accuracy of engineering cost estimates used to evaluate the economic effects of applying SO_2 and NO_x controls to existing coal-fired utility boilers.

This report presents the SO_2/NO_x control technology cost and performance estimates developed for twelve coal-fired utility plants in Ohio, Kentucky, and the Tennessee Valley Authority (TVA) system. The following procedures were used to develop the cost performance estimates: select plants with boilers representative of the population, conduct plant visits and collect site-specific data, develop boiler/control specific retrofit difficulty factors, and develop boiler/plant-specific cost and performance estimates for the SO_2 and NO_x controls selected for evaluation. This performance and cost estimating process is dynamic: it incorporates recommendations from a technical advisory group and participating utilities, as well as experience from site visits and performance/ cost evaluations.

1.1 CONTROL TECHNOLOGIES EVALUATED

The commercial and developmental SO_2 and NO_x control technologies selected for inclusion in the program are listed in table 1-1. Evaluated qualitatively without cost estimates were fluidized bed combustion and coal gasification. Additional technologies which were at first considered--chemical coal cleaning, pressurized fluidized bed combustion, and advanced

TABLE 1-1. EMISSION CONTROL TECHNOLOGIES SELECTED

	Species Controlled		Development Status		
	SO_2	NO_x	Commercial	Limited Commercial Experience	Near Commercial Demonstration
Lime/limestone (L/LS) flue gas desulfurization (FGD)	X		X		
Additive enhanced L/LS FGD	X		X		
Lime spray drying (LSD) FGD[a]	X		X		X
Physical coal cleaning (PCC)	X		X		
Coal switching and blending (CS/B)	X		X		
Low-NO_x combustion (LNC)		X		X	
Furnace sorbent injection (FSI) with humidification (LIMB)	X				X
Duct spray drying (DSD)	X				X
Natural gas reburning (NGR)[b]	X	X			X
Selective catalytic reduction (SCR)		X		X	
Fluidized bed combustion (FBC) or coal gasification (CG) retrofit[c]	X	X		X	

[a] Commercial on low-sulfur coals, demonstrated at pilot scale on high sulfur coals.
[b] For wet bottom boilers and other boilers where LNC is not applicable.
[c] Evaluated qualitatively as combined life extension and SO_x/NO_x control option. No costs were developed.

SO_2/NO_x (combined) control devices--were not included in this study due to their general inapplicability to retrofit situations and early development status.

All of the cost estimates were developed using computer-based simulation models. This approach was taken because of the large quantity of data which needed to be accessed, used in computation, and stored. Although a number of mainframe- and personal computer-based models were evaluated, the Integrated Air Pollution Control Systems (IAPCS) cost model was finally selected for use in this study because of its versatility. The IAPCS model has been upgraded to include the technologies being evaluated in this program.

1.2 PLANTS VISITED

Four key criteria were used to select the plants to be visited. First, plant selection focused on boiler types and sizes accounting for the majority of SO_2 emissions. Second, within the limits of the first criterion, the selected plants were representative examples of the diversity of the boiler population. Third, due to costs, the number of plants selected for detailed study were limited to less than thirty. And fourth, the plants selected contained multiple boilers of diverse types.

Boilers in the top 200 SO_2-emitting plants were categorized by generating capacity, coal percent sulfur, firing types, age, and capacity factor. The top 200 plants were ranked according to their diversity, and the 30 highest-scoring plants were evaluated by boiler category to see if a realistic, proportional sample had been achieved successfully. Plants near the bottom of the list with disproportional, extreme ratings were replaced in order to ensure the representativeness of the sample. From this list of 30 plants 12 plants were chosen for evaluation: 5 in Ohio and 7 in Kentucky and the TVA system (Tennessee and parts of Alabama and Kentucky).

The Ohio and Kentucky plants were selected for evaluation first because of the opportunity to conduct the program jointly with Ohio and Kentucky State Acid Rain (STAR) programs. In addition to one TVA plant in Kentucky, three TVA plants outside Kentucky were included through TVA's cooperative participation in the Kentucky STAR program. These were considered to be representative of the top 200 SO_2 emitting plants. Table 1-2 lists the plant/boiler characteristics for these twelve plants.

Prior to the plant site visit, a plant profile was completed using sources of public information, a primary reference being Department of Energy (DOE), Energy Information Agency (EIA) Form 767. The plant profile was designed to include all of the information and data needed for performance/cost analyses. The plant profile data were verified and completed using information obtained during the one-day site visit.

1.3 SUMMARY OF PERFORMANCE AND COST ESTIMATION METHODOLOGY

Using the data and information obtained from the plant visits, site-specific cost estimates were developed using the IAPCS cost model. These cost estimates reflect site-specific retrofit costs because retrofit factors, scope (cost) adders and performance estimates were developed and input to the model. Figure 1-1 schematically presents the methodology used to develop the retrofit costs using the IAPCS cost model.

For all technologies, retrofit factors and scope adders were developed using the Electric Power Research Institute (EPRI) report entitled "Retrofit FGD Cost Estimating Guidelines." Retrofit factors are process area multipliers which adjust the cost model to reflect the following location and retrofit effects:

- Location
    - regional material and labor costs,
    - foundation and support structure costs related to soil conditions and seismic zone, and
    - freeze protection costs.
- Retrofit
    - access/congestion,
    - underground obstructions, and
    - distance between process areas.

TABLE 1-2. BOILER CHARACTERISTICS OF PLANTS EVALUATED USING DETAILED PROCEDURES

Plant Name (State)	Boiler Number	Net Dependable Generating Capacity Per Unit, MW	Age, Yr	Capacity Factor Percent	Coal Sulfur, Percent	Firing Type
Burger (OH)	1-4	30	40-43	29-30	3.4	Roof
	5-6	45	37	31	3.4	Roof
	7-8	75	32	38-56	3.4	Wall
Conesville (OH)	1-2	125	28-30	32-26	2.9	Cyclone
	3	165	25	37	2.9	Wall
	4	720	14	58	2.9	Tangential
	5-6	375	9-11	45-48	4.1	Tangential
Muskingum River (OH)	1-2	205	33-34	63	4.4	Wall (Wet Bottom)
	3-4	215	29-30	55	4.4	Cyclone
	5	585	19	61	4.4	Wall
Sammis (OH)	1-4	180	25-28	44-57	0.9	Wall
	5	300	20	53	2.4	Wall
	6-7	600	16-18	44-51	2.4	Wall
Stuart (OH)	1-4	559	13-17	54-66	1.2	Wall (Cell Burner)
Brown (KY)	1	100	30	50	1.9	Wall
	2	156	24	65	1.9	Tangential
	3	410	16	65	1.9	Tangential
Elmer Smith (KY)	1	151	23	30	2.9	Cyclone
	2	265	13	50	2.9	Tangential
Big Sandy (KY)	1	260	24	63	1.2	Wall
	2	800	18	63	1.2	Wall
Paradise (KY)	1-2	704	24	30	2.9	Cyclone
	3	1150	17	30	2.9	Cyclone
Johnsonville (TN)	1-4	125	35-36	39	1.7	Tangential
	5-6	147	34-35	30	1.7	Tangential
	7-10	173	28-29	41	1.7	Wall
Cumberland (TN)	1-2	1300	14	60	2.9	Wall
Colbert (AL)	1-4	200	32	50	2.3	Wall
	5	550	22	50	2.3	Wall

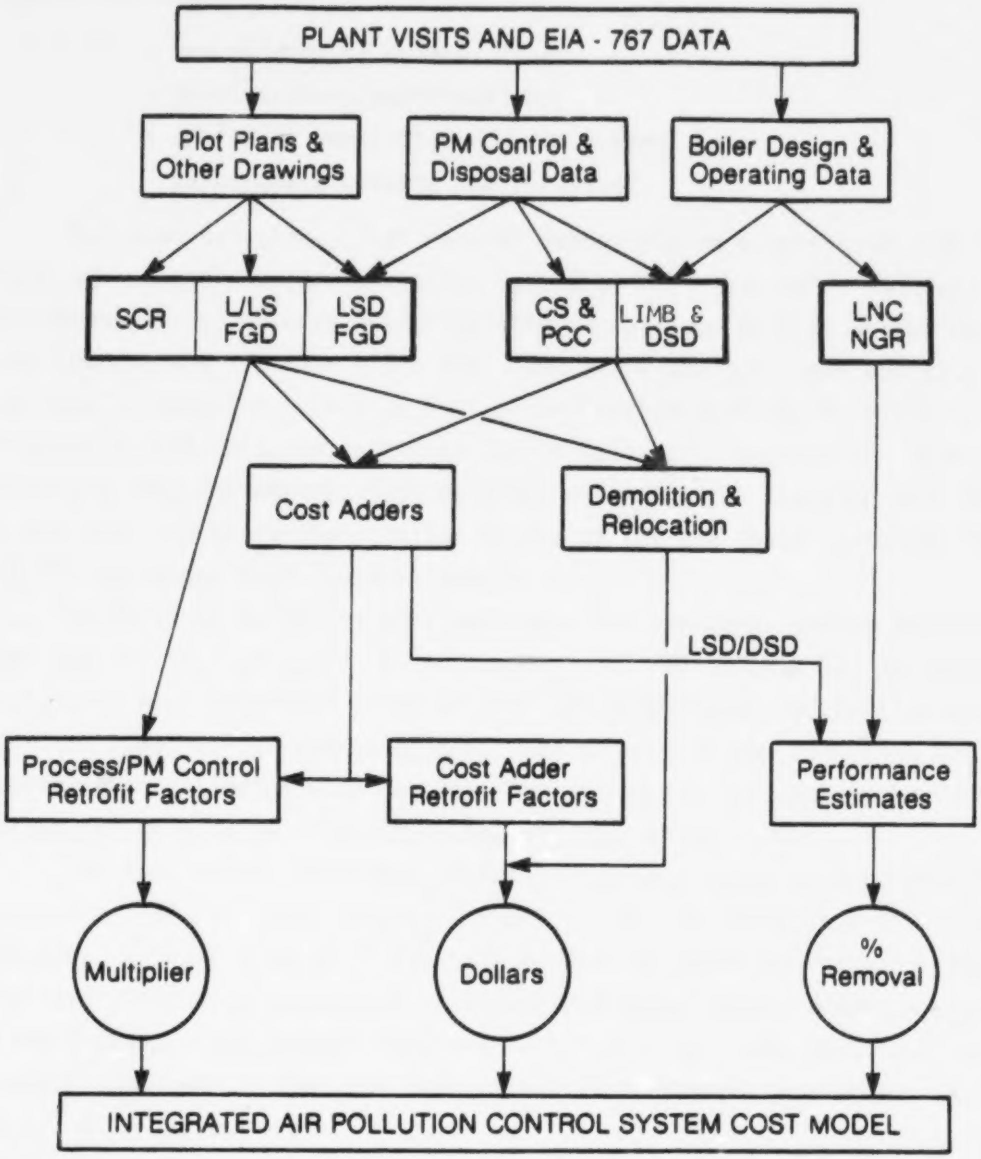

PLANT VISITS AND EIA - 767 DATA
Plot Plans & Other Drawings
PM Control & Disposal Data
Boiler Design & Operating Data
SCR
L/LS FGD
LSD FGD
CS & PCC
LIMB & DSD
LNC NGR
Cost Adders
Demolition & Relocation
LSD/DSD
Process/PM Control Retrofit Factors
Cost Adder Retrofit Factors
Performance Estimates
Multiplier
Dollars
% Removal
INTEGRATED AIR POLLUTION CONTROL SYSTEM COST MODEL

Figure 1-1. Methodology using IAPCS cost model.

Scope adders are additional costs that would be included in the cost of retrofit but are not included in the cost model algorithm bases. These cost adders include:

- new chimney or chimney liner,
- draft control modifications,
- equipment demolition and replacement, and
- particulate control modifications.

For coal switching, fuel cost differentials were developed from the cost of currently used coals using data from FERC Form 423. Two fuel price differentials (FPD) were evaluated: the current low to high sulfur coal FPD and the current FPD plus $15 a ton. The $15 a ton fuel cost addition was assumed to span the potential fuel price premium that would result if extensive coal switching occurred due to acid rain legislation. For coal cleaning, the incremental fuel cost was determined by assuming that the plant coal had properties similar to one of the six coals contained in the IAPCS cost model coal cleaning module.

Performance estimates were developed for the spray drying technologies and the low NO_x combustion technologies. LSD FGD and DSD SO_x performance estimates were developed based on flue gas temperature and particulate control type: ESP or fabric filter. Low NO_x burner and over-fire air performance estimates were developed by evaluating the furnace heat release rates versus flue gas residence time and coal properties.

The full report describes in detail the procedures used to develop the retrofit factors, scope adders, and LNC control NO_x reduction estimates. However, a brief summary of the cost results arranged by control technology follows. The costs presented are levelized annual costs based on August 1987 dollars. The capital recovery factor and operating cost levelization factor are based on the 1986 EPRI Technical Assessment Guidelines report and are: 0.18 capital recovery factor and 1.45 operation cost levelization factor.

1.3.1 FGD Cost Estimates

Figure 1-2 and table 1-3 summarize the plant level cost estimates developed for conventional L/LS FGD. The cost of the conventional L/LS FGD configurations are based on compliance with New Source Performance Standards (30-day rolling average). Figure 1-2 schematically presents the annual cost versus SO_x reduction for the 12 plants evaluated. Table 1-3 summarizes the plant level average annual unit cost of control and retrofit difficulty range for each boiler/plant.

Note that L/LS FGD was applied only to units 6 and 7 at the Sammis Plant. This was due to the extreme retrofit difficulty for unit 6. The retrofit difficulty and annual cost of control would be much greater for units 1-5 than for unit 6, making it unlikely that conventional FGD would be applied to units 1-5. The plants having the lowest unit cost of control were Cumberland and Muskingum River. The Cumberland units are large (1300 MW each), fire a 2.9% high sulfur coal, and have moderate retrofit difficulty. The Muskingum River Plant units have low unit cost of control even though units 1-4 have high retrofit difficulty factors; these units have high capacity factors (40 to 60%) and burn a very high 4.4% sulfur coal.

Table 1-4 presents the costs estimated for low cost L/LS FGD. The low cost FGD configuration was evaluated to show the potential cost reductions for the following FGD system design:

- additive enhanced lime/limestone slurry to reduce absorber size and allow flue gas bypass for reheat because of the high removal efficiencies possible,
- elimination of spare absorber,
- maximize absorber size to benefit from economies of scale, and
- combine flue gases from adjacent boilers in to a larger system to maximize benefits of economies of scale for entire system.

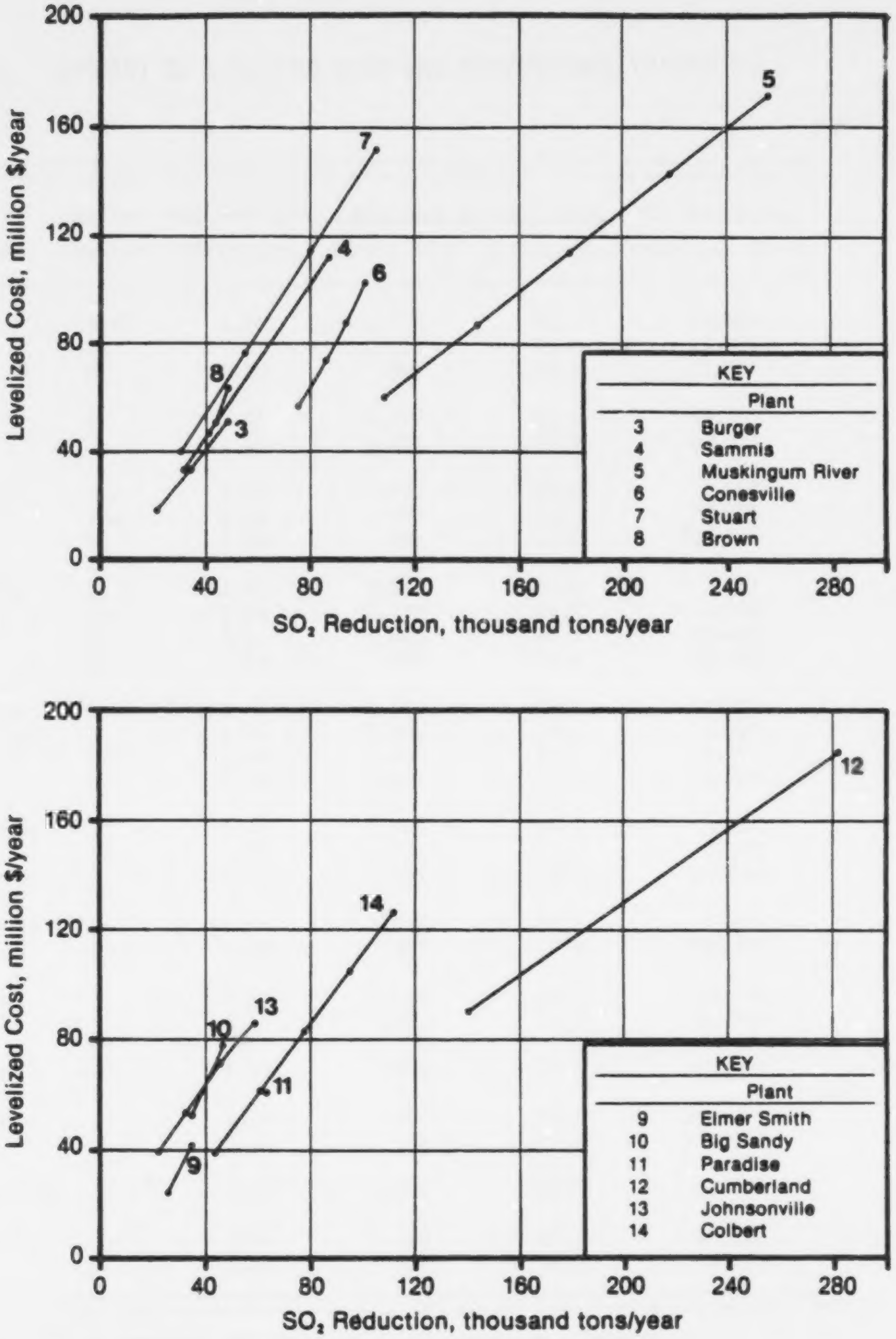


Figure 1-2. L/LS FGD cost versus SO_2 reduction.

TABLE 1-3. SUMMARY OF L/LS FGD COST AND PERFORMANCE ESTIMATES

Plant Name	Boiler Number	FGD Retrofit Difficulty	Levelized Annual Costs		SO_2 Reduction
			($/ton SO_2)	(mills/kWh)	(tons per year)
Burger	1-6*	1.30	1,218	32.2	14,500
	7	1.26	1,112	29.4	13,300
	8	1.29	845	22.3	19,500
Sammis	6	3.01	1,397	24.2	46,200
	7	1.86	1,122	19.5	39,900
Muskingum River	1-2	1.70	671	22.8	76,600
	3-4	1.66	704	23.9	71,300
	5	1.54	496	16.9	106,800
Conesville	1	1.54	1,961	40.2	7,100
	2	1.54	1,779	36.5	8,100
	3	1.51	1,526	31.3	10,900
	4	1.55	703	14.4	74,500
J. M. Stuart	1	1.43	1,429	13.1	25,200
	2	1.45	1,449	13.3	24,900
	3	1.44	1,469	13.5	24,300
	4	1.44	1,283	11.8	29,700
E. W. Brown	1	1.70	2,306	30.2	5,700
	2	1.60	1,526	20.0	11,600
	3	1.41	1,035	13.5	30,000
Elmer Smith	1	1.66	1,906	42.5	8,900
	2	1.26	867	19.4	26,000
Big Sandy	1	1.50	2,018	16.4	11,600
	2	1.54	1,416	11.5	35,800
Paradise	3	1.35	956	18.0	63,300
Cumberland	1	1.46	598	12.6	141,000
	2	1.40	575	12.1	141,000
Johnsonville	1-10*	1.48	1,213	16.7	60,000
Colbert	1-4*	1.54	1,222	22.2	69,200
	5	1.38	807	14.7	44,200

* Boilers have combined FGD because flue gases are already combined in common duct run to chimney.

TABLE 1-4. SUMMARY OF LOW COST L/LS FGD COST ESTIMATES

Plant Name	Boiler Number	Levilized Annual Cost ($/ton SO_2)	Levilized Annual Cost (mills/kWh)	Ratio Low Cost Versus Conventional L/LS ($/ton basis)
Burger	1-8	574	15.1	0.57
Sammis	6	1,010	17.5	0.72
	7	811	14.1	0.72
Muskingum	1-4	383	13.0	0.56
River	5	377	12.8	0.76
Conesville	1-4	535	11.0	0.55
J. M. Stuart	1-2	849	7.8	0.59
	3-4	806	7.4	0.59
E. W. Brown	1-2	989	13.4	0.55
	3	782	10.6	0.76
Elmer Smith	1	1,305	29.3	0.68
	2	589	13.2	0.68
Big Sandy	1-2	962	7.8	0.62
Paradise	3	723	13.6	0.76
Cumberland	1-2	492	10.8	0.72
Johnsonville	1-10	993	14.2	0.82
Colbert	1-4	585	10.6	0.48
	5	574	10.4	0.71

This system configuration could potentially be used if SO_2 reduction compliance is based on annual averages. The low cost FGD configuration would not have sufficient spare absorber capacity to achieve compliance with NSPS. All of the cost reduction options included in the low cost configuration are being used commercially in the U. S., or Germany and Japan. However, the combination of all of the cost reduction options has not been demonstrated commercially to evaluate the overall system reliability and the impact of system reliability on plant operating costs and regulatory compliance.

Table 1-4 also presents the ratio of the low cost FGD to the conventional L/LS FGD with additives. The low cost configuration reduces annual costs by 18 to 52 percent. The plants having the greatest reduction in cost have small boilers which were combined into a large system. The plants having the least reduction in cost have large boilers, or the boiler flue gases were already combined (Johnsonville).

Figure 1-3 and table 1-5 summarize the plant level cost estimates developed for lime spray drying. Two control options were considered for the retrofit of this technology: (1) reuse of the existing ESP and (2) a new fabric filter. For the following boiler situations reuse of the existing ESP was not considered:

- when the specific collection area (SCA) of the existing ESP was small (<43.3 m^2/actual m^3/sec or 220 ft^2/1,000 acfm), and
- when the addition of new plate area was impractical (e.g., roof mounted ESPs).

In such cases, a new fabric filter was required for particulate control after the spray drying reactor. However, reuse of the ESP was considered impractical for many units. Boilers where LSD with ESP reuse (LSD + ESP) and LSD with new fabric filters (LSD + FF) were applied are identified on figure 1-3 and table 1-5. Note that the cost of retrofitting new fabric filters results in a high retrofit difficulty factor and a high cost of control. For the Sammis plant, only unit 7 was evaluated because retrofit of LSD FGD would be very costly for units 1-6.

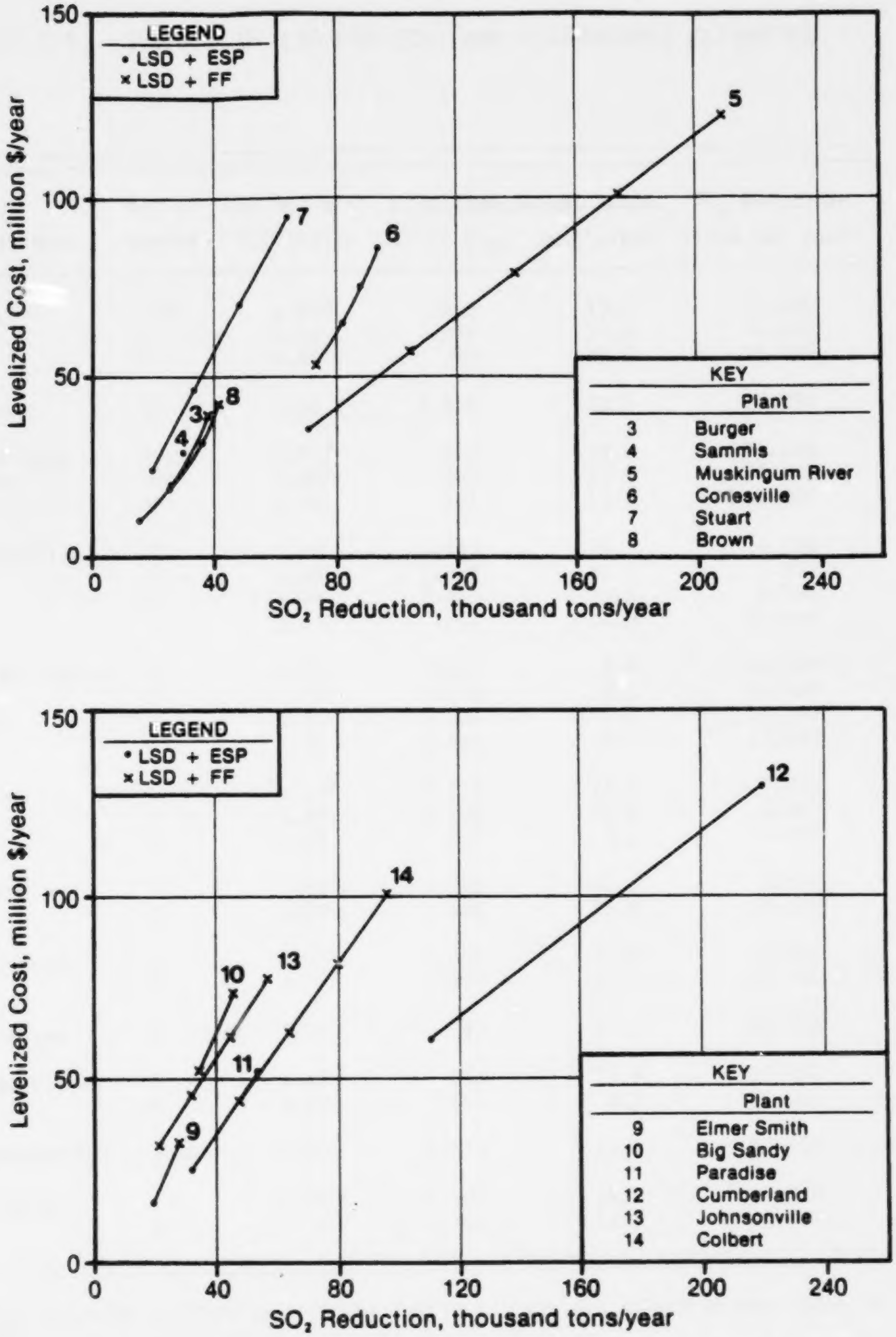


Figure 1-3. LSD FGD cost versus SO_2 reduction.

TABLE 1-5. SUMMARY OF LSD FGD COST AND PERFORMANCE ESTIMATES

Plant Name	Boiler Number	FGD Retrofit Difficulty	Levelized Annual Costs ($/ton SO_2)	(mills/kWh)	SO_2 Reduction (tons per year)
Burger	1-6	1.50[a]	1,463	37.1	13,900
	7	1.19	954	17.9	9,400
	8	1.19	704	13.2	13,900
Sammis	7	1.93	1,012	12.5	28,400
Muskingum River	1-2	2.01[a]	612	19.1	70,200
	3-4	1.96[a]	650	21.2	68,500
	5	1.70	501	11.0	69,000
Conesville	1	1.63	1,649	28.7	6,100
	2	1.63	1,479	25.7	6,800
	3	1.60	1,260	21.9	9,300
	4	2.07[a]	751	14.8	71,600
J. M. Stuart	1	1.70	1,634	8.8	14,900
	2	1.72	1,678	9.1	14,700
	3	1.71	1,709	9.2	14,400
	4	1.70	1,422	7.7	17,600
Brown	1	2.00[a]	2,016	25.3	5,500
	2	1.69	1,194	13.2	9,800
	3	1.25	814	8.5	24,000
Smith	1	1.88[a]	1,923	41.4	8,600
	2	1.38	846	13.9	19,100
Big Sandy	1	1.88[a]	1,953	14.8	10,900
	2	1.75[a]	1,507	11.8	34,400
Paradise	3	1.71	947	15.1	53,700
Cumberland	1	1.66	624	10.3	110,000
	2	1.32	555	9.2	110,000
Johnsonville	1-10	1.82[a]	1,350	17.9	57,500
Colbert	1-4	1.80[a]	1,171	19.7	64,000
	5	1.30	784	10.1	31,300

[a] This retrofit difficulty includes fabric filter; all others assume reuse of ESP.

1.3.2 Coal Switching and Cleaning

Figure 1-4 and table 1-6 summarize the plant level cost estimates developed for coal switching (CS). For these technologies a number of plants and units were not considered applicable for CS for the following reasons: the units already burn a low sulfur coal; the plant receives coal by conveyor from local mines and the construction of truck, rail, and barge receiving facilities would be very costly; and the units have wet bottom boilers which can burn only coals having special ash fusion properties. As figure 1-4 shows, the unit cost of control for coal switching is very dependent upon the fuel cost differential. The impact of particulate control upgrades and coal handling upgrades are generally small by comparison.

Table 1-7 summarizes the plant level cost of physical coal cleaning (PCC). A number of plants were not evaluated for PCC because the coal already is extensively cleaned, and the IAPCS coal cleaning costs are based on the cleaning run of mine coals. As table 1-7 shows, the unit cost and the amount of SO_2 reduction obtained by coal cleaning are both low.

1.3.3 Sorbent Injection Cost and Performance Estimates

Two sorbent injection technologies in active research and development were evaluated in this study: furnace sorbent injection (FSI) with humidification (LIMB) and duct spray drying (DSD). Figure 1-5 and table 1-8 summarize the plant level cost estimates developed for these technologies. Not all boilers were considered good candidates for these technologies for the following reasons:

- LIMB and DSD with ESP reuse were not considered practical for boilers having an ESP SCA < 43.3 m^2/actual m^3/sec or 220 ft^2/1,000 acfm, and
- DSD with ESP reuse was not considered if the duct residence time from the injection point after the air heater to the ESP inlet was less than 2 seconds (<100 feet of duct length).

For boilers where ESP reuse was not considered practical, DSD with new

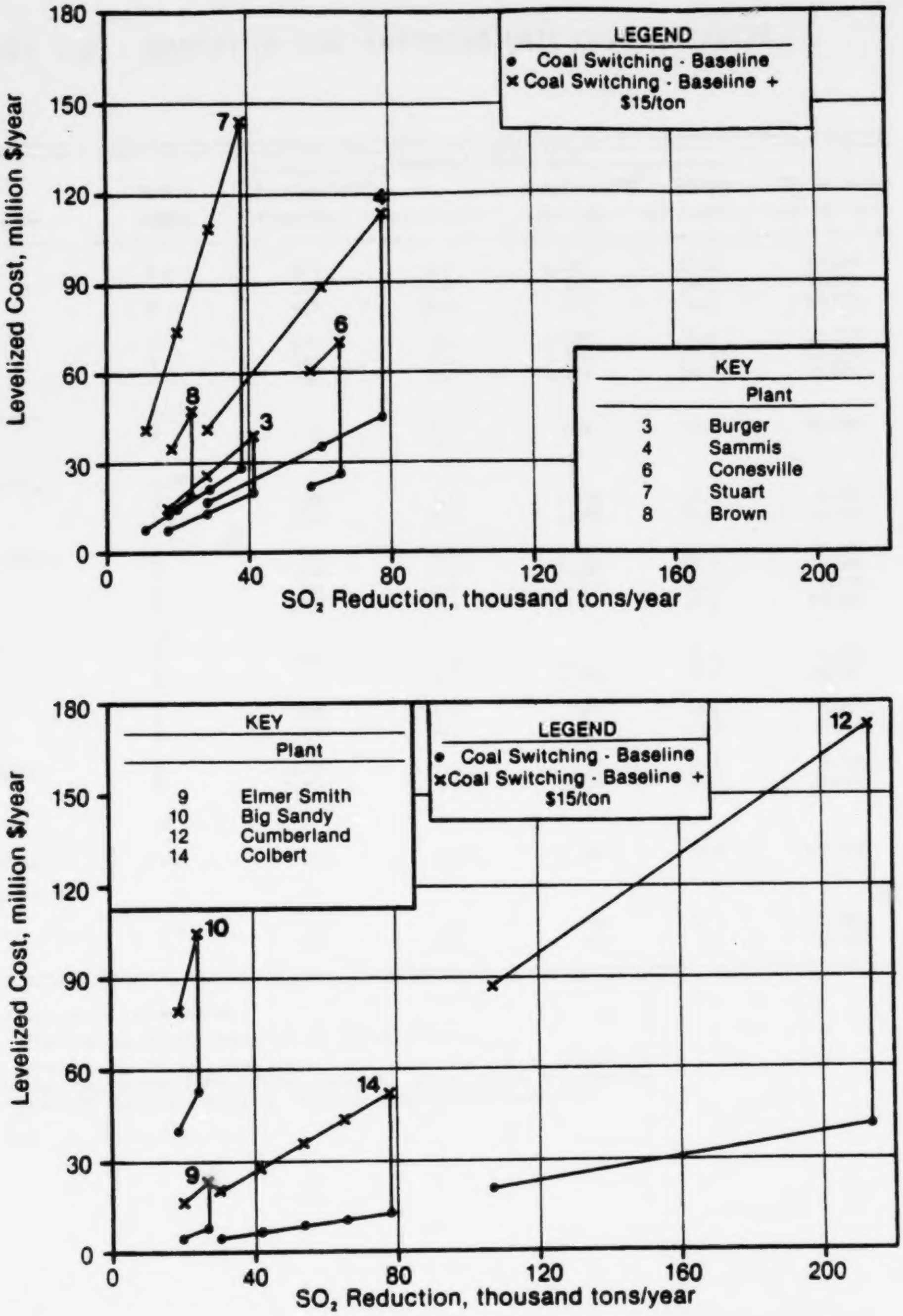


Figure 1-4. Coal switching costs versus SO_2 reduction.

TABLE 1-6. SUMMARY OF COAL SWITCHING UNIT COST ESTIMATES

		Levelized Annual Cost				
	Boiler	Baseline FPD[a]		Baseline FPD[a] + $15/ton		SO_2 Reduction
Plant Name	Number	(\$/ton SO_2)	(mills/kWh)	(\$/ton SO_2)	(mills/kWh)	(tons per year)
Burger	1-6	571	12.9	1,044	23.4	12,900
	7	480	10.8	945	21.2	11,300
	8	459	10.3	913	20.5	16,600
Sammis	5	584	7.1	1,467	17.8	16,800
	6	585	7.1	1,471	17.8	32,300
	7	591	7.2	1,484	18.0	27,900
Muskingum River	1-4[b]					
	5	176	5.4	523	16.0	96,300
Conesville	1-2[b]					
	3	458	7.2	1,158	18.1	8,300
	4	392	6.1	1,073	16.8	56,900
J. M. Stuart	1	763	2.5	3,862	12.7	9,000
	2	764	2.5	3,865	12.7	9,000
	3	769	2.5	3,874	12.7	8,700
	4	736	2.4	3,811	12.5	10,700
Brown	1[c]					
	2	838	6.2	2,117	15.6	6,500
	3	777	5.7	2,056	15.1	16,900
Smith	1	395	6.7	981	16.6	6,700
	2	238	4.0	802	13.6	19,600
Big Sandy	1	2,235	9.6	4,313	18.5	6,100
	2	2,226	9.5	4,304	18.4	18,100
Paradise	3[b]					
Cumberland	1-2	189	3.0	809	13.0	106,900
Johnsonville[c]						
Colbert	1-4	182	2.2	693	8.6	11,800
	5	146	1.8	657	8.1	30,100

[a] FPD - Fuel Price Differential.

[b] Coal switching was not evaluated for wet bottom boilers.

[c] Coal switching was not evaluated for boiler at this plant, since boilers have small roof-mounted ESPs. Adding additional plate area is not possible, and the use of SO_3 conditioning is likely to be marginally beneficial.

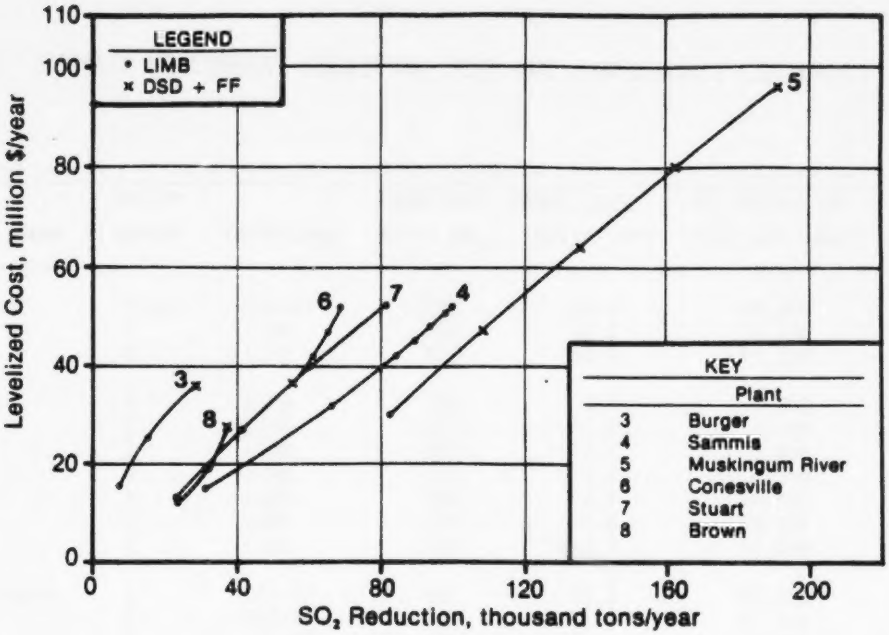
TABLE 1-7. SUMMARY OF COAL CLEANING UNIT COST ESTIMATES

Plant Name	Boiler Number	Levelized Annual Cost Baseline FPD[a] ($/ton SO_2)	Levelized Annual Cost Baseline FPD[a] (mills/kWh)	SO_2 Reduction (tons per year)
Burger	1-6	600	5.7	5,200
	7	397	3.7	4,700
	8	363	3.4	6,900
Sammis	5	381	2.5	9,200
	6	382	2.5	17,700
	7	386	2.6	15,300
Muskingum River[b]				
Conesville[b]				
J. M. Stuart	1	1,546	3.2	5,700
	2	1,549	3.2	5,600
	3	1,556	3.2	5,500
	4	1,502	3.1	6,700
Brown	1[c]			
	2	389	3.2	7,400
	3	375	3.1	19,100
Smith	1	843	5.9	2,800
	2	527	3.7	8,100
Paradise[b]				
Cumberland[b]				
Johnsonville[c]				
Colbert	1-4	676	3.7	5,300
	5	595	3.3	13,400

[a] FPD - Fuel Price Differential.

[b] Physical coal cleaning (PCC) was not evaluated because coal presently is washed to reduce sulfur and ash prior to firing. Insufficient data were available to evaluate the cost/performance of advanced coal cleaning.

[c] PCC not evaluated, since boilers have small roof-mounted ESPs. Adding additional plate area is not possible, and the use of SO_3 conditioning is likely to be marginally beneficent.



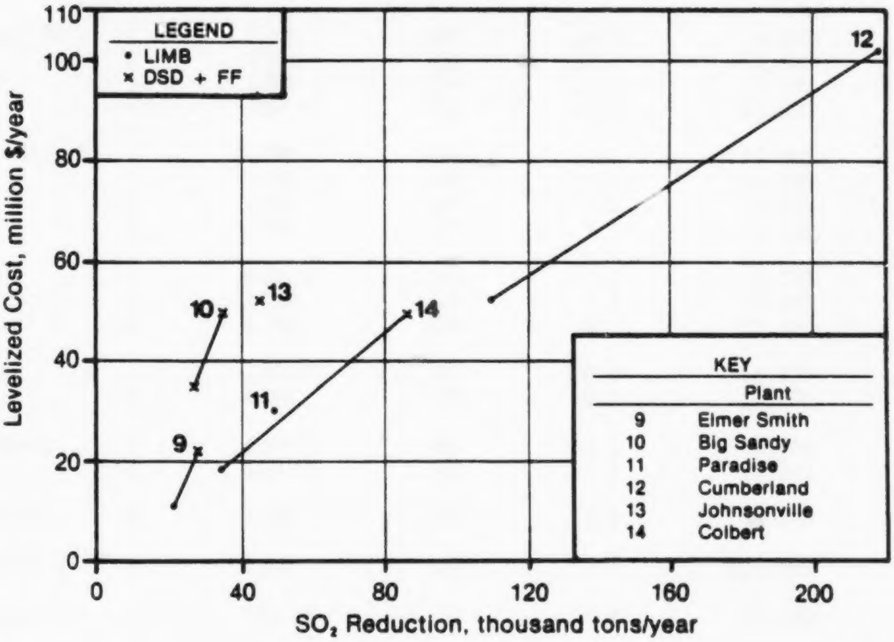


Figure 1-5. LIMB (70 % removal) and DSD costs versus SO_2 reduction.

TABLE 1-8. SUMMARY OF SORBENT INJECTION COST AND PERFORMANCE ESTIMATES

Plant Name	Boiler Number	Technology	Levelized Annual Cost		SO_2 Reduction
			($/ton SO_2)	(mills/kWh)	(tons per year)
Burger	1-6	DSD-FF	1,284	25.4	10,900
	7	LIMB	602	12.4	10,300
	8	LIMB	519	10.6	15,200
Sammis	1	LIMB	736	3.7	3,500
	2	LIMB	725	3.6	3,500
	3	LIMB	693	3.5	3,800
	4	LIMB	622	3.1	4,500
	5	LIMB	540	7.3	18,600
	6	LIMB	476	6.4	35,900
	7	LIMB	499	6.7	31,000
Muskingum River	1	DSD-FF	581	14.3	27,800
	2	DSD-FF	583	14.4	27,700
	3	DSD-FF	628	16.0	27,100
	4	DSD-FF	640	16.3	26,400
	5	LIMB	364	9.6	83,100
Conesville	1	LIMB	897	14.3	5,600
	2	LIMB	832	13.3	6,300
	3	LIMB	754	12.0	8,500
	4	DSD-FF	652	10.0	55,900
J. M. Stuart	1	LIMB	655	4.7	19,600
	2	LIMB	688	4.8	19,400
	3	LIMB	607	4.3	18,900
	4	LIMB	577	4.1	23,100
Brown	1	DSD-FF	1,814	17.8	4,300
	2	LIMB	713	7.3	9,000
	3	LIMB	563	5.7	23,300
Smith	1	DSD-FF	1,583	26.6	6,700
	2	LIMB	588	10.2	20,200
Big Sandy	1	DSD-FF	1,684	10.0	8,600
	2	DSD-FF	1,302	7.9	26,900
Paradise	3	LIMB	613	9.0	49,300
Cumberland	1-2	LIMB	469	7.7	219,400
Johnsonville	1-10	DSD-FF	1,141	11.8	44,900
Colbert	1-4	DSD-FF	585	8.2	53,100
	5	LIMB	567	8.0	34,400

fabric filter was evaluated. The costs presented for FSI assume 70% SO_x control and 35 percent sorbent utilization.

As figure 1-5 shows, the cost of sorbent injection at Big Sandy and Johnsonville is very high as a result of the need to retrofit new fabric filters.

1.3.4 Retrofit of Fluidized Bed Combustion and Coal Gasification

The retrofit potential of FBC or CG with reuse of the existing steam turbine and other plant facilities was qualitatively assessed for each boiler using the following criteria: boiler size, boiler heat rate, boiler capacity factor, boiler age, particulate control performances, and SO_2/NO_x emission levels. The following boilers were found to qualify as potential candidates regarding the boiler age and size criteria:

- Burger boilers 1-8,
- Sammis boilers 1-4,
- Muskingum River boilers 1-4,
- Conesville boilers 1-3,
- Smith boiler 1,
- Big Sandy boiler 1,
- Johnsonville boilers 1-10, and
- Colbert boilers 1-4.

However, other criteria are also important and are discussed in more detail in each plant section.

1.3.5 Low NO_x Combustion

Figure 1-6 and table 1-9 summarizes the plant level cost and performance estimates for application of low NO_x burners on dry bottom wall-fired boilers, over-fire air on tangential fired boilers and natural gas reburn on other boilers (wet bottom and roof fired). As figure 1-6 and table 1-9 show the unit cost of low NO_x burners and over-fire air is low

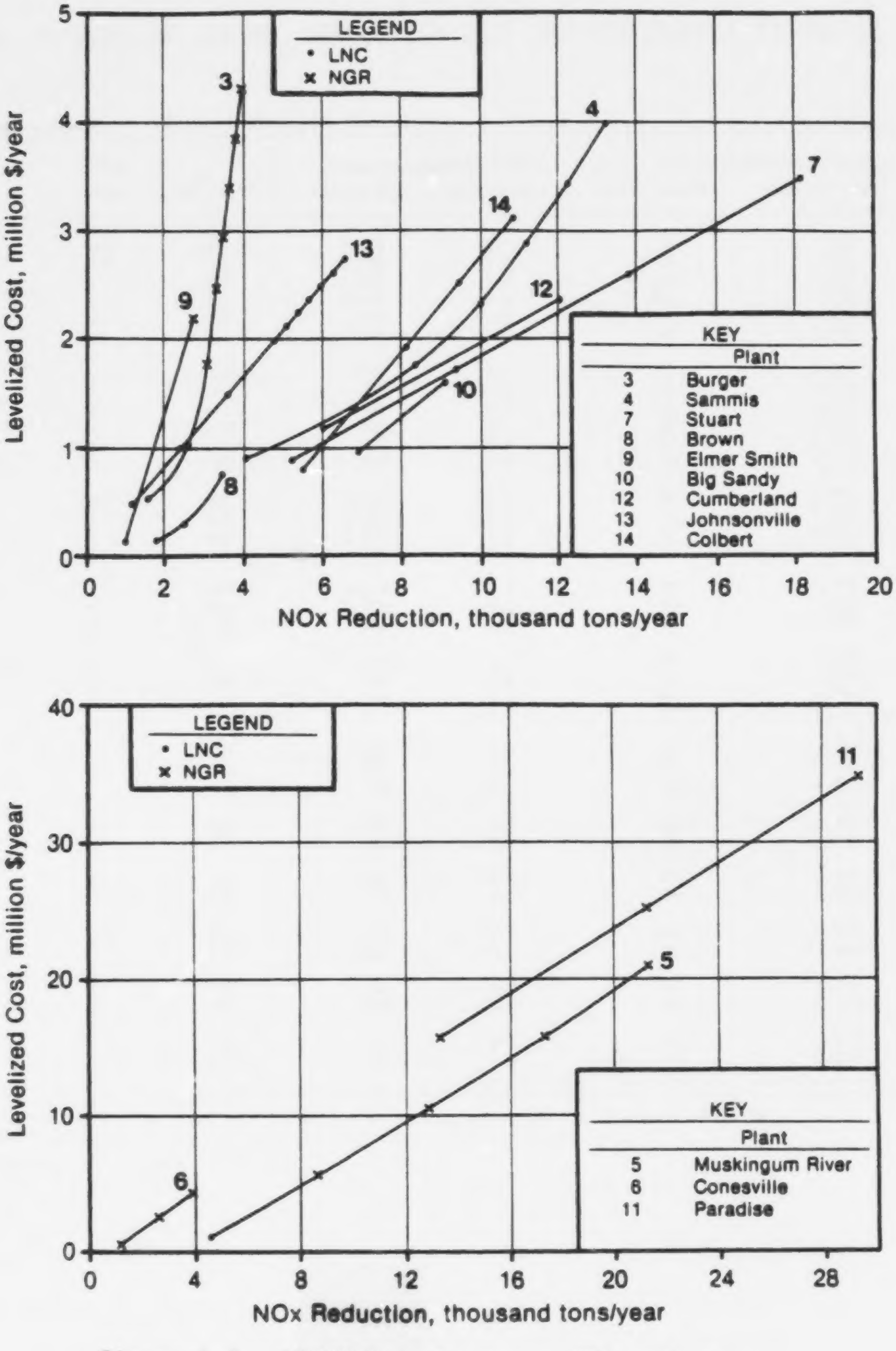


Figure 1-6. LNC/NGR costs versus NO_X reduction.

TABLE 1-9. SUMMARY OF LOW NO_x COMBUSTION COST AND PERFORMANCE ESTIMATES

			Levelized Annual Costs		NO_x Reductions	
Plant Name	Boiler Number	LNC[a] or NGR[b]	($/ton NO_x)	(mills/kWh)	(Efficiency-%)	(tons per year)
Burger	1-2	NGR	2,797	6.0	50	160
	3-4	NGR	2,765	5.9	50	170
	5	NGR	2,631	5.4	50	260
	6	NGR	2,536	5.4	50	300
	7	LNB	478	1.0	50	1,070
	8	LNB	325	0.7	50	1,570
Sammis	1	LNB	527	0.8	35	1,000
	2	LNB	515	0.8	35	1,000
	3	LNB	482	0.7	35	1,100
	4	LNB	407	0.6	35	1,400
	6	LNB	194	0.3	40	4,600
	7	LNB	224	0.4	40	4,000
Muskingum River	1-2	NGR	1,237	4.6	50	4,200
	3	NGR	1,147	4.7	50	4,300
	4	NGR	1,150	4.7	50	4,200
	5	LNB	203	0.3	30	4,400
Conesville	1	NGR	1,389	5.2	50	1,300
	2	NGR	1,359	5.1	50	1,500
	3	LNB	473	1.0	50	1,100
J. M. Stuart	1	LNB	197	0.3	35	4,400
	2	LNB	199	0.3	35	4,400
	3	LNB	204	0.3	35	4,200
	4	LNB	167	0.3	35	5,200
Brown	1	LNB	456	1.0	50	1,000
	2	OFA	183	0.1	25	700
	3	OFA	103	0.1	20	1,800
Smith	1	NGR	1,192	5.2	50	1,700
	2	OFA	152	0.1	25	1,000
Big Sandy	1	LNB	281	0.4	35	2,400
	2	LNB	144	0.2	35	6,930
Paradise	1-2	NGR	1,200	4.7	50	8,000
	3	NGR	1,182	4.7	50	13,300
Cumberland	1	OFA	200	0.2	20	6,000
	2	OFA	200	0.2	20	6,100
Johnsonville	1-6	LNB	370	0.3	25	300
	7-10	LNB	427	1.0	50	1,200

[a] LNC types: Low NO_x burners (LNB) for dry bottom wall-fired boiler and over-fire air (OFA) for tangential-fired boiler.

[b] NGR used on all other boilers.

(<$400/ton). However, for plants/boilers where NGR is applied, the unit costs are much higher ($800 to $1200 per ton). This is due to the high cost of natural gas relative to coal ($2 per million Btu fuel price differential).

1.3.6 Selective Catalytic Reduction Cost Estimates

Figure 1-7 and table 1-10 summarize the plant level cost estimates for application of SCR. With the exception of Sammis units 1-6, tail-end systems were assumed (reactor being downstream of particulate control or scrubbers). For Sammis units 1-6, space limitations require that a hot side, high dust system configuration be used after the economizer and before the air heater. Use of the tail-end system minimizes unit downtime, which reduces the uncertainty of estimating the cost of replacement power, and maximizes the catalyst life (cost trade-off with energy penalty associated with flue gas reheating).

The cost estimates for SCR presented in this report are based on one year of catalyst life. German and Japanese experience indicates that a 3- to 5-year life is probable for many applications. If a 3-year catalyst life is assumed, the annual cost of SCR would be 40 to 50 percent less than that presented in this report.

5.0 CONCLUSIONS

For each of the SO_2 and NO_X control technologies evaluated under this program, a number of different factors will affect control cost and performance for retrofit applications at coal-fired boilers. These boilers were built or were under construction before the 1971 new source performance standards, and plant layout and boiler design did not consider the application of SO_2 and NO_X controls.

Although there are any number of factors which can affect retrofit cost/performance, table 1-11 identifies those which were found to have significant effect on cost/performance. For the L/LS FGD technologies, site access/congestion and flue gas ducting distances were major factors. For LSD FGD the need to add new particulate control also was a major factor.

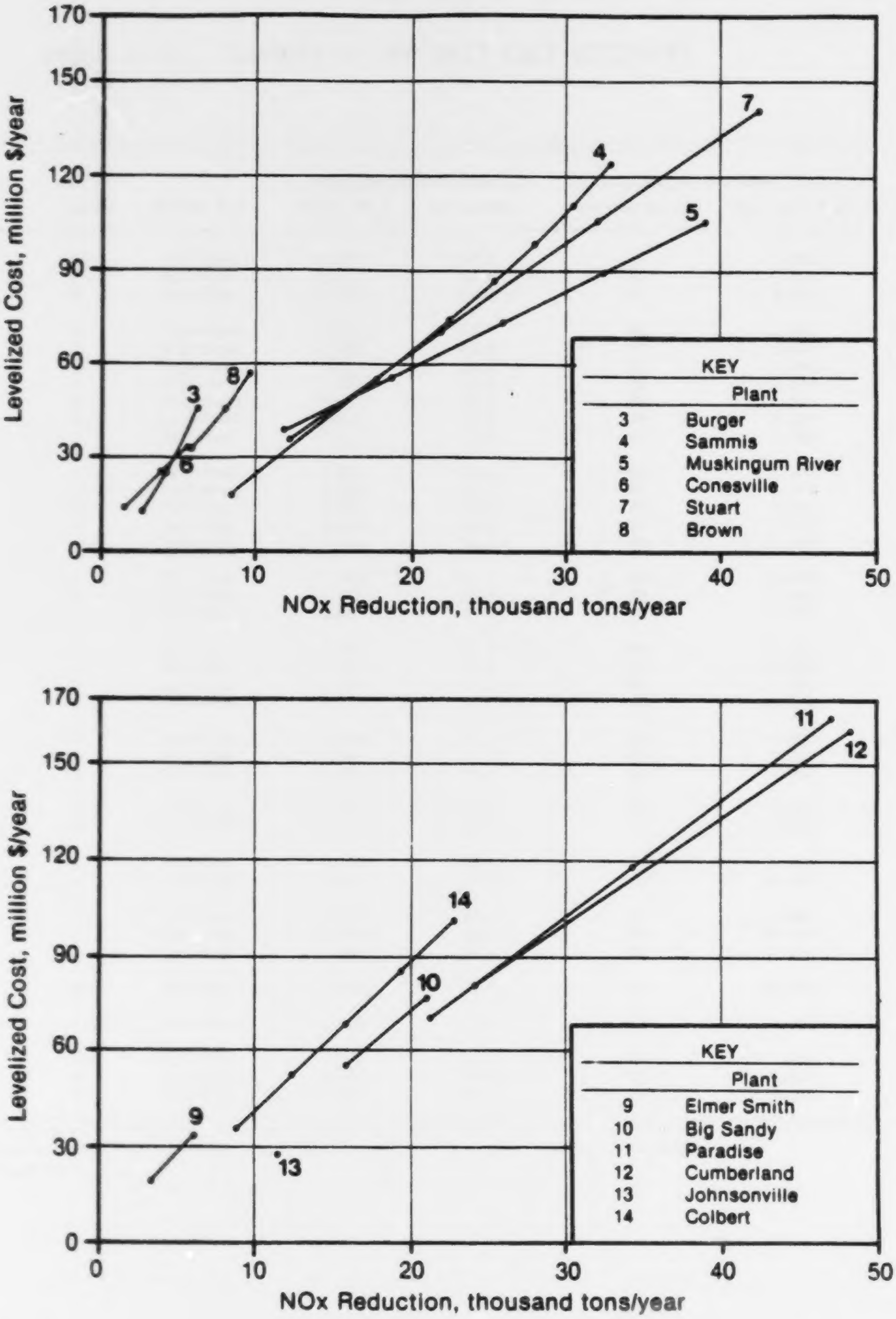


Figure 1-7. SCR costs versus NO_X reduction.

TABLE 1-10. SUMMARY OF SCR UNIT COST ESTIMATES

Plant Name	Boiler Number	System Type	Levelized Annual Costs ($/ton NO_x)	Levelized Annual Costs (mills/kWh)	NO_x Reductions (Efficiency-%)	NO_x Reductions (tons per year)
Burger	1-6	Tail-End	10,940	38.6	80	1,900
	7	Tail-End	7,272	24.8	80	1,700
	8	Tail-End	5,004	17.1	80	2,500
Sammis	1	High-Dust	5,048	17.4	80	2,400
	2	High-Dust	4,940	17.0	80	2,400
	3	High-Dust	4,632	16.0	80	2,600
	4	High-Dust	3,937	13.6	80	3,100
	5	High-Dust	4,094	14.2	80	4,800
	6	High-Dust	3,992	13.8	80	9,200
	7	Tail-End	2,242	7.8	80	8,000
Muskingum River	1	Tail-End	2,352	14.1	80	6,800
	2	Tail-End	2,363	14.1	80	6,700
	3	Tail-End	2,585	16.8	80	6,900
	4	Tail-End	2,567	16.7	80	6,700
	5	Tail-End	3,302	12.2	80	11,600
Conesville	1	Tail-End	5,705	34	80	2,100
	2	Tail-End	5,071	30.2	80	2,300
	3	Tail-End	8,067	27.3	80	1,800
J. M. Stuart	1	Tail-End	3,497	12.8	80	10,000
	2	Tail-End	3,527	12.9	80	10,000
	3	Tail-End	3,600	13.2	80	9,700
	4	Tail-End	2,977	10.9	80	11,900
Brown	1	Tail-End	6,548	22.8	80	1,500
	2	Tail-End	5,846	14.6	80	2,200
	3	Tail-End	5,704	14.2	80	5,700
Smith	1	Tail-End	5,272	36.9	80	2,800
	2	Tail-End	5,847	16.6	80	3,300
Big Sandy	1	Tail-End	4,161	15.0	80	5,200
	2	Tail-End	3,474	12.5	80	15,900
Paradise	1	Tail-End	3,612	22.9	80	12,900
	2	Tail-End	3,694	23.4	80	12,900
	3	Tail-End	3,304	20.9	80	21,300
Cumberland	1-2	Tail-End	3,346	12.1	80	24,100
Johnsonville	1-10	Tail-End	2,428	6.4	80	11,400
Colbert	1-3	Tail-End	4,728	17.1	80	3,500
	4	Tail-End	4,864	17.6	80	3,500
	5	Tail-End	4,004	14.5	80	8,800

[a] Costs are based on one-year catalyst life. Costs based on three-year catalyst life would be 40 to 50 percent less.

TABLE 1-11. RETROFIT FACTORS AFFECTING COST/PERFORMANCE

Control Technology	Access and Congestion	Ducting Distance	Particulate Control	Additional Boiler Type	Boiler Configuration
Lime/Limestone Flue Gas Desulfurization	X	X			
Lime Spray Drying	X	X	X		
Coal Switching/ Blending			X	X	
Physical Coal Cleaning			X	X	
Furnace Sorbent Injection with Humidification (LIMB)			X		
Duct Spray Drying		X	X		
Low NO_x Combustion				X	X
Natural Gas Reburning				X	X
Selective Catalytic Reduction	X	X		X	

For coal switching and coal cleaning the major retrofit factors, excluding fuel price differential, were particulate control upgrade costs and boiler performance impacts. The latter was not assessed because detailed coal analyses were not available. As a result, coal switching was not evaluated for wet bottom boilers, since boiler performance impacts are likely to be significant.

For the sorbent injection technologies, LIMB and DSD, particulate control upgrade costs would have the greatest impact. Additionally, for DSD, sufficient duct residence time must be available in order to guarantee good droplet drying.

For the LNC and NGR technologies, boiler type and configuration are important issues. Low NO_X burners were applied only to dry bottom, wall-fired boilers. Over-fire air was applied only to tangential-fired units. NGR was applied to wet bottom boilers and other miscellaneous boiler types. Boiler heat release rates and residence times in different furnace zones would have significant effects on NO_X removal efficiency for LNC and NGR technologies.

Selective catalytic reduction costs would be greatly affected by access and congestion near the economizer area for high dust applications and the chimney area for tail-end applications and by flue gas ducting distances. For high dust systems, boiler downtime costs and catalyst life would be significant cost/performance factors. For tail-end systems, the energy penalty for preheat is balanced by increased catalyst life and reduced catalyst costs.

As discussed earlier, the objective of the program is to improve significantly the cost/performance estimates used to evaluate impacts of potential acid rain legislation. The information presented in this document is very useful in that regard. However, cost comparisons have not been made for retrofit options for specific boilers at each plant. For example, costs have been projected for L/LS FGD and the other SO_2 control technologies (LSD FGD, CS, PCC, LIMB, and DSD), but no comparison has been made regarding the best option.

Although the cost/performance information presented is a realistic guide regarding the degree of retrofit difficulty for each control option evaluated, the technologies evaluated in this study are at various stages of commercial development:

- extensive commercial application in the U. S. (L/LS FGD and CS),
- commercial application in other countries (SCR) and in the U. S. on low sulfur coals (LSD FGD),
- limited commercial application in the U. S. (PCC and LNC), and
- early stages of commercial demonstration (LNC, FBC, CG, NGR, and LIMB), and of pilot-scale demonstration (DSD).

Because there is a higher degree of uncertainty regarding the cost/performance for these technologies which do not have extensive commercial application in the U. S., no attempt has been made in this study to identify a best option for each plant/boiler.

Additionally, a utility company's decision concerning which retrofit control to apply to a given boiler is very complex and would be based on the following criteria:

- system reduction target and degree of flexibility regarding means to achieve the target,
- current and future load pattern for each boiler with or without controls,
- cost of purchased power and planned new capacity,
- cost of capital and current/future financial strength, and
- public utility commission and state/region regulatory agency attitudes.

SECTION 2

COST ESTIMATION PROCEDURES FOR RETROFIT OF SO_x AND NO_x CONTROLS

This section presents the procedures used in this study to estimate the cost and performance of retrofitting SO_x and NO_x controls at coal-fired power plants. The Integrated Air Pollution Control System (IAPCS) cost model was used to develop the control technology cost estimates (1). However, the model cost algorithms do not reflect the cost and performance impacts of retrofitting controls. Therefore, to adjust the IAPCS model algorithms for retrofit situations, retrofit factors and cost adders were developed for each of the control technologies to reflect site-specific control costs. Additionally, for the spray drying and low NO_x combustion modifications, performance estimates were developed to account for non-ideal situations that will occur with the retrofit of these control technologies.

In order to adjust the IAPCS cost and performance estimates to reflect site-specific retrofits, retrofit difficulty multipliers (retrofit factors) and scope adder costs were developed. Retrofit factors adjust cost model process area costs to reflect the cost impacts of:

- site access and congestion,
- underground obstructions, and
- distances between process areas.

Scope adders adjust cost model estimates by adding costs that were not addressed in the cost model algorithms. Typical scope adders that are not included in cost algorithms developed for new plant control systems or in retrofit control system bases include:

- chimney liner or new chimney,
- demolition/relocation of existing facilities,
- additional particulate control facilities,

- conversion of wet ash handling systems to dry handling, and
- air heater modifications/replacement.

For many of the technologies, scope adders and retrofit factors were not applicable or had already been included in the cost algorithm assumptions. The applicability of these retrofit issues for each technology is briefly discussed under each technology discussion. Table 2-1 summarizes the retrofit factors and scope adders that were addressed for each of the control technologies evaluated under the program.

The Electric Power Research Institute (EPRI) "Retrofit FGD Cost-Estimating Guidelines" (2) were used to develop retrofit factors and scope adders for lime/limestone (L/LS) FGD and lime spray drying (LSD) FGD. To the extent possible, the information and methodology contained in the EPRI guidelines document was used for the other technologies (excluding low NO_x combustion technologies). Section 2.1 describes the procedures used to develop the retrofit difficulty factors, scope adders, and performance estimates for low NO_x combustion modifications. The retrofit factors, scope adders, and performance estimates were then input to IAPCS.

The retrofit of fluidized bed combustion (FBC) or coal gasification (CG) with gas turbine and reuse of the existing unit steam turbine was evaluated qualitatively. No cost estimates were developed because the application of these technologies is heavily weighted toward the economic benefits of life extension and heat rate improvements. The evaluation criteria used to qualitatively assess the potential for each boiler as a candidate for FBC or CG retrofit are also described in Section 2.1.

Section 2.2 describes the IAPCS model for each of the technologies evaluated. Section 2.3 describes the economic and financial assumptions used to develop the control technology cost estimates.

2.1 RETROFIT FACTORS AND SCOPE ADDERS

This section explains the retrofit factor and scope adder development procedures in more detail. For the most part, the procedures for all technologies were based on the EPRI retrofit FGD cost estimating guidelines. Scope adder costs for conversion of wet ash handling systems to dry handling

Table 2-1. RETROFIT COST AND PERFORMANCE INPUTS TO IAPCS[a] MODEL

		Retrofit Factors Addressed			Scope Adders Addressed			
Control Technology	Performance Estimates[b]	Access and Congestion	Underground Obstructions	Process Area Distance	Chimney or Liner	Demolition and Relocation	Additional Particulate Control	Wet to Dry Ash Handling
Lime/Limestone Flue Gas Desulfurization		X	X	X	X	X		X
Lime Spray Drying	X	X	X	X	X	X	X	X
Coal Switching							X	
Physical Coal Cleaning							X	
Furnace Sorbent Injection	X[c]					X	X	X
Duct Spray Drying	X[c]	X			X	X	X	X
Low NO_x Combustion								
Natural Gas Reburning								
Selective Catalytic Reduction	X[c]	X	X			X		

[a] IAPCS = Integrated Air Pollution Control System (1)

[b] Made using procedures not included in IAPCS model.

[c] For particulate control retrofits.

and improvements to rail spurs and coal handling systems were taken from other references and are not addressed in the EPRI procedures. Scope adder costs for particular control system upgrades, flue gas humidification, and new particulate controls are based on IAPCS cost algorithms.

A detailed description of the EPRI retrofit FGD cost-estimating procedures/methodology is presented under the L/LS and LSD FGD discussion. For the other technologies where these procedures were used, only a brief discussion of when these procedures were used is presented.

Repowering of older boilers for combined life extension and SO_x/NO_x control is handled qualitatively under this effort. A brief discussion identifies the boiler characteristics that could make a particular boiler/turbine a good candidate for replacing the boiler with fluidized bed combustion (FBC) or coal gasification (CG) technologies. In this study it was assumed that with the retrofit of FBC or CG the steam turbine and other plant facilities would be reused.

2.1.1 Lime/Limestone and Lime Spray Drying Flue Gas Desulfurization

The retrofit factor and retrofit cost methodology used for L/LS FGD and LSD FGD is from the EPRI guidelines mentioned above (2). These procedures were used to develop retrofit factors incorporated into the IAPCS cost model to estimate site-specific retrofit capital and operating costs.

2.1.1.1 EPRI Methodology--

The EPRI methodology is based on application of a series of factors to the cost of a new FGD system. The factors correct for site specifics such as process variables, location, and retrofit difficulty. The cost estimates calculate total retrofit capital requirement, first year operating and maintenance (O&M) cost, and total levelized retrofit FGD costs. Economic evaluations in this report are based on the capital cost of new FGD systems as developed in the "Economic Evaluation of FGD Systems" (3). Cost estimates can be calculated for two levels of detail:

- detailed retrofit cost estimates that may require several days of effort and some preliminary design work, and

- generalized retrofit cost estimates that require 1-2 hours and no preliminary design work.

However, for this study only the detailed procedures for developing site-specific retrofit capital costs were used to develop the process area retrofit factors, the scope adders, and engineering and general facility indirect percentages.

Figure 2-1 schematically presents the methodology used to adjust new plant cost for site-specific retrofit situations that typically require equipment and/or work not necessary in a new plant FGD system. Two types of cost adjustments are made to new plant costs: (1) cost adders that account for scope adjustments and (2) cost multipliers that account for location and retrofit factors.

Cost adders typically encountered include:

- a new chimney, or chimney liner for protection of the existing chimney against the acidic effects of a wet scrubber,
- structural improvement of the boiler to provide pressure surge protection, or a draft control system to prevent surges in the fire box, and
- any demolition and/or equipment relocation necessary to make room for the new equipment.

Cost adders typically contribute an additional 5 to 20 percent to a new FGD system's capital cost, excluding new particulate control equipment.

New plant process area costs and scope adjustments are adjusted by process, location, and retrofit factors. Process factors include the following:

- unit size,
- gas flow per MW,
- percent sulfur in the coal, and
- SO_2 removal efficiency.

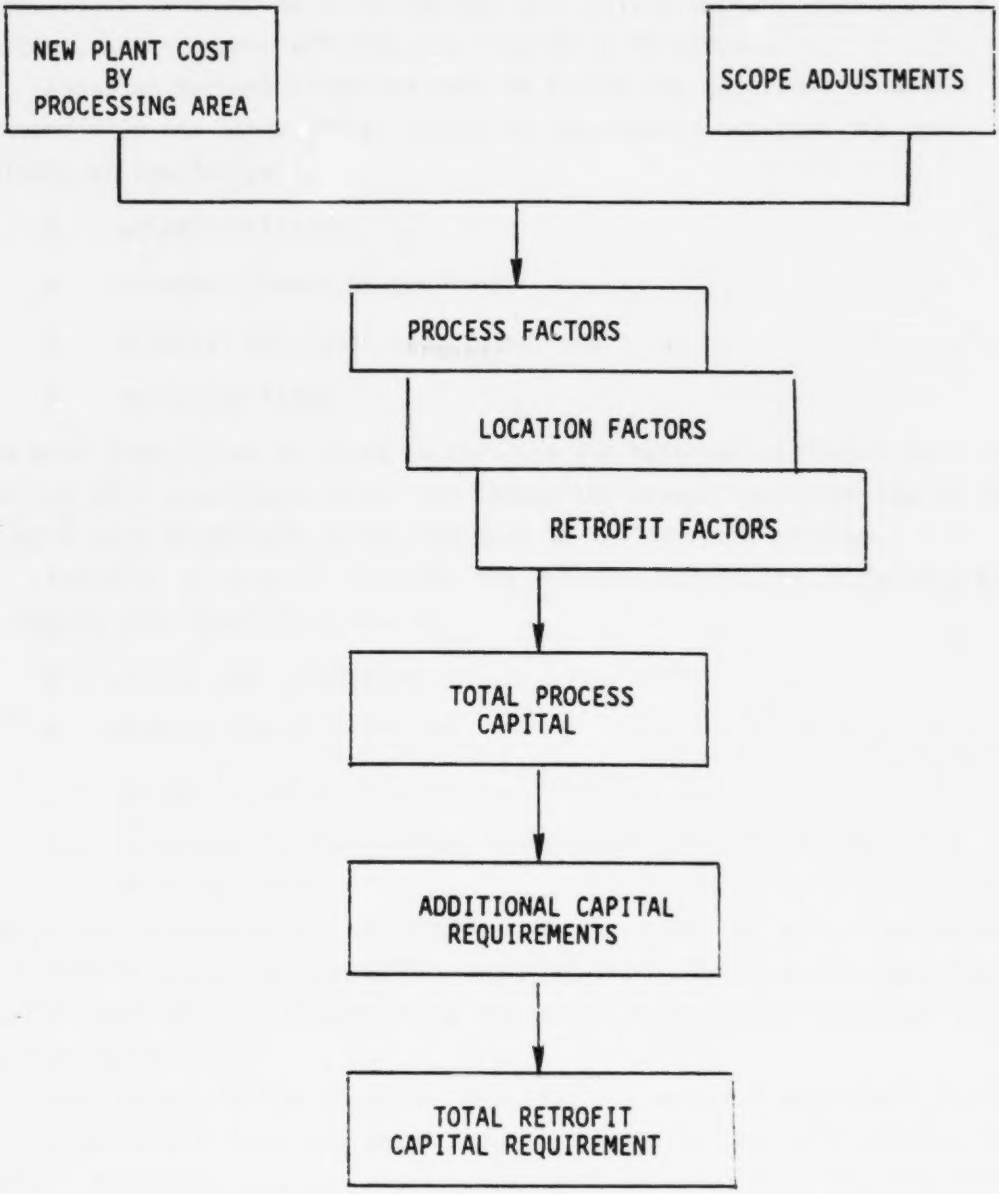

NEW PLANT COST BY PROCESSING AREA
SCOPE ADJUSTMENTS
PROCESS FACTORS
LOCATION FACTORS
RETROFIT FACTORS
TOTAL PROCESS CAPITAL
ADDITIONAL CAPITAL REQUIREMENTS
TOTAL RETROFIT CAPITAL REQUIREMENT

Figure 2-1. FGD Retrofit Cost Methodology.

These process adjustments modify the EPRI base costs for various plant capacities: from 100 MW up to 700 MW, coal sulfur content from 1.0 to 6.0 percent, and scrubber efficiencies from 50 to 90 percent.

Location factors allow the user to adjust the cost from Kenosha, Wisconsin to any other state. Location adjustments consider the cost effects of the following:

- seismic activity,
- climate (freeze protection),
- material and labor cost index, and
- soil conditions.

The most significant of these factors are the material and labor cost index and the soil conditions, which can change the actual installed capital cost by more than 50 percent versus the cost at a different location.

Retrofit adjustments consider the retrofit difficulty as defined by the following site-specific criteria:

- access and congestion,
- underground obstructions,
- ductwork length and tie-in difficulty, and
- distances to the scrubber for sorbent preparation and waste handling areas.

Access and congestion and the ductwork distance are the major contributors to retrofit costs. Accessibility and congestion alone can increase the capital cost of any one particular subsystem of an FGD installation by more than 50 percent.

Application of the location, process, and retrofit adjustment factors to the new plant costs and scope adder costs yields the total process cost (TPC). Additional capital requirements must be calculated from the TPC to derive the total capital requirements. Two of these, engineering and general facilities, are increased above the base (new plant) to account for site-specific factors. Engineering percentage is increased to account for seismic zone, access/congestion and underground obstruction differences between the new plant bases. General facilities percentage is increased to account for additional plant roads, buildings, etc., not included as part of the cost of either installing equipment.

Finally, the EPRI retrofit FGD cost-estimating procedures apply the following capital requirements to the TPC to obtain the total retrofit capital cost:

- project and process contingency,
- escalation to the date of construction,
- allowance for funds during construction (AFDC),
- royalty allowance,
- inventory capital, and
- preproduction operating costs.

2.1.1.2 Adjustment of IAPCS Costs--

The EPRI retrofit FGD cost-estimating guidelines provide a method for adjusting new plant estimates of capital and annual cost of FGD applications based on other EPRI cost studies. For this study, it was decided to use the IAPCS model that uses a cost-estimating model developed by the Tennessee Valley Authority (TVA) (4). Therefore, it was necessary to incorporate the location and retrofit factors developed from the EPRI retrofit FGD cost-estimating guidelines into IAPCS. This was done by inputting retrofit and location factor multipliers and indirect percentages developed from the EPRI procedures.

The following location and retrofit factor multipliers and indirect percentages were input to the IAPCS model:

- Total Process Capital - multiplied by the retrofit difficulty and location factors;
- Engineering Percentage - includes retrofit impact of seismic zone, access/congestion and underground obstructions;
- Location Factor Percentage - includes impact of seismic/climate zone, soil conditions, and labor/material index;

- General Facilities Percentage - includes demolition/relocation of plant roads, ash ponds, and buildings.
- Process and Project Contingencies - overall percentages per EPRI guidelines;
- Escalation to Date of Construction - Chemical Engineering index (5) for August 1987; and
- Allowance for Funds During Construction (AFDC), Inventory Capital and Pre-Production costs - per EPRI Technical Assessment Guidelines (6).

The total process capital aggregate location and retrofit factor multiplier input to the IAPCS model was calculated as follows:

$$\text{Retrofit Factor Multiplier} = \frac{\text{EPRI Guideline Retrofit TPC}}{\text{EPRI Guideline New Plant TPC}}$$

This factor includes the impacts of scope adder and retrofit difficulty, but divides out the impact of location and process factors because they are included in the values used in both the denominator and numerator. As such, a weighted average location factor was developed and was incorporated directly into the IAPCS model. The process factor is not needed in IAPCS because the model cost algorithm already accounts for process factors.

Although not included as scope adder options in the EPRI retrofit guidelines, scope adders for converting wet fly ash handling systems to dry and upgrading existing railroad track were developed. The conversion of wet fly ash systems to dry was made assuming that the fly ash would be needed for sludge stabilization, except for forced oxidation cases. Additionally, if the ESP was reused for a LSD retrofit, wet sluicing of spray dryer spent sorbent would cause line plugging problem and eliminate recovery of unused sorbent by conventional recycling methods. Ash handling costs were developed from an EPA study of ash conveyance system costs (7). The costs of upgrading and adding railroad tracks were estimated as $250,000 and $1,000,000 per mile, respectively (8).

2.1.1.3 Overall Retrofit Factor--

When presenting the cost results for L/LS FGD and LSD FGD in this report, an overall retrofit factor is also presented. The overall retrofit factor is based on the EPRI procedures and was calculated as follows:

$$\text{Overall} = \frac{\text{EPRI Guidelines Total Retrofit Capital Cost}}{\text{EPRI Guidelines Total New Plant Capital Cost}}$$

This factor includes the impact of increased engineering and general facilities fees, scope adders, and process area retrofit difficulty. However, it does not include the location factor, which would be the same for either a new plant or retrofit FGD system at the same location. For the LSD FGD cases, this factor does include the cost impact of new fabric filter but does not include costs for ESP upgrades.

2.1.2 Coal Switching and Cleaning

In evaluating the cost impacts of coal switching and cleaning at a plant, a larger number of retrofit issues need to be addressed in addition to fuel cost differentials. These include the cost of new/upgraded coal receiving, storage, and handling facilities; boiler operating impacts (capacity, slagging, fouling, erosion, etc); and ESP impacts. For the twelve plants evaluated, ash analysis, washability data, and grindability data were not available. As a result, a semi-quantitative analysis of boiler impacts and coal cleaning cost-effectiveness was not conducted.

Consequently, scope adder costs and access and congestion difficulty for particulate control upgrades were the focus of the retrofit difficulty evaluation conducted. The IAPCS cost model was used to evaluate the need for ESP upgrades that included: SO_3 conditioning, additional plate area, and ash handling/disposal costs. When additional plate area was required, the access/congestion factor developed using the EPRI retrofit FGD cost estimating guidelines procedures was applied to the cost of plate area addition.

Additionally, four situational factors were identified where the procedures used under this study would likely underestimate the cost of coal switching and cleaning. These situations are discussed below.

2.1.2.1 Boiler/Plants Not Evaluated--

After reviewing comments on the draft report, it was decided to eliminate presenting costs for coal switching at boiler/plant situations where extensive boiler derating may occur due to ash fusion properties and where an existing mine-mouth plant does not have facilities for receiving low sulfur coals.

As a result, eight wet bottom boilers were not evaluated for coal switching, due to the cost of firing low sulfur coals with certain ash fusion properties. These costs are difficult to quantify for the following reasons: (1) a western subbituminous coal would result in extensive derating, (2) use of a western butuminous coal would have high transportation costs, and (3) use of an eastern bituminous coal of limited supply would likely result in a large fuel price differential. For all cases, the cost would tend to favor the use of other technologies.

One plant, Muskingum River, was not evaluated for coal switching because this plant only receives coal only by conveyor from local mines. Receiving coal by truck, rail, or barge is not anticipated to be cost effective because:

- no local supplies of low sulfur coal exist within a reasonable truck haul distance,
- no railroad tracks are available nearby capable of carrying large shipments of coal and, further, upgrade of existing tracks would be expensive, and
- coal barges cannot navigate the adjacent waterway.

Additionally, a number of plants firing coals that are extensively washed were not evaluated for physical coal cleaning (PCC). These plants were not evaluated because no coal washability data were available and the IAPCS model PCC coal washing costs are based on cleaning run of mine coal.

Coal cleaning was not evaluated for the boilers at the following plants: Connesville, Muskingum River, Paradise, Johnsonville, Brown, and Cumberland.

2.1.2.2 ESP Upgrade Difficulty--

The IAPCS model ESP upgrade module was used to evaluate ESP upgrade costs associated with coal switching and cleaning. ESP performance is affected by reducing the coal sulfur content and changing ash loading and ash resistivity. The IAPCS model estimates the ESP plate area needed for particulate control after coal switching/cleaning and also estimates the cost of SO_3 conditioning if any additional plate area is needed. It is assumed that SO_3 conditioning will reduce needed plate area by 25 percent. This assumption is likely to be an optimistic one for many situations, thereby understating the needed plate area. Additionally, for many boilers that have small ESPs (<250 SCA), adding additional plate area may be difficult because limited access and site congestion make this an unlikely option. For these situations, it is very common in the industry to build new ESPs and using old, small ESPs. This ensures compliance with particulate emission regulations for the typical range of operating situations encountered due to variable boiler/operating conditions and coal properties.

The cost impact of new ESPs for boilers having marginal ESP plate areas after SO_3 conditioning is discussed in the report text. For other boilers, coal switching was not evaluated because the roof-mounted ESPs were not candidates for upgrade: Johnsonville 1-10 and Brown 1.

2.1.2.3 Inadequate Coal Storage Facilities--

A number of plants have facilities for receiving low sulfur coals by truck/rail/barge. In fact, most plants can receive coal at least two of these ways. However, not all plants can segregate coal piles for blending coals or supply different coals to different boilers. For such plants, the report text indicates that the capital cost requirements for coal switching are understated. In general, however, the costs of segregation and blending facilities are not significant relative to the fuel price differential.

2.1.2.4 Small Boiler Derate Impacts--

In the draft report for the five plants evaluated in Ohio, an attempt was made to estimate boiler derating for the following boiler operating factors:

- pulverizer capacity,
- slagging,
- fouling,
- erosion, and
- flue gas/heat input capacity.

However, because the existing coal ash analyses and grindability data were not available, these factors for both the existing coal and switch coal had to be assumed based on information on coals having the same sulfur/ash/heating value characteristics. Since the approach was too qualitative, this effort was discontinued, except to eliminate wet bottom boilers expected to have major derate potential when switching to generally available low sulfur eastern coals. However, even a small derate (10-15 percent) can have a significant cost impact depending on the cost of purchasing replacement power or if new capacity must be built to replace the lost power generating capacity. On the other hand, coal switching can also result in reduced boiler operating and maintenance cost and can also result in an increase in capacity. However, these benefits are generally small relative to the impact of the fuel price differential.

2.1.3 Furnace Sorbent Injection and Duct Spray Drying

These technologies are in various stages of research and development and are being developed specifically for retrofit. As such, many costs of retrofit are built into the base case design and costs. The IAPCS model cost algorithms for furnace sorbent injection (FSI) with humidification and duct spray drying (DSD) with calcium-based sorbents were used in this study. The focus of this study was to identify retrofit modifications not covered by the developers. These include particulate control upgrades, conversion of wet fly ash handling systems to dry systems and demolition/relocation of existing equipment.

Of particular importance to the cost of all the technologies will be the ability of the existing particulate control device to be upgraded. The IAPCS model assumes that the benefits of humidification makes all ESPs candidates for reuse. However, numerous boilers have ESPs with SCAs less than the 220 square feet per 1,000 cubic feet, that IAPCS estimates is the minimum required after humidification. These ESPs are generally old and are situated in areas with limited access making plate area addition difficult. Also many of these boilers have short duct residence time between the air heater outlet and the ESP, making the application of humidification or duct spray drying technically infeasible. For these boiler situations, the FSI cost estimates developed were not presented in the report. However, the option of DSD with a new fabric filter was evaluated, and the cost results are presented.

For the boilers where DSD with new fabric filters was evaluated, scope adder costs and fabric filter access/congestion retrofit factors were developed. The scope adder costs included building demolition/replacement, new flue gas ducting, and flue gas ducting demolition. For the boilers where reuse of the existing ESPs for FSI and DSD was evaluated, scope adder costs for converting wet fly ash conveying systems to dry handling were developed, if needed.

Although access/congestion factors were developed for the sorbent preparation/receiving areas, these factors were not used except for plants where a high value was assumed. This did not occur for any of the 12 plants evaluated under this study. It was felt that the large project contingency used for these technologies adequately covered average access/congestion situations and sorbent conveying distances (500-1,500 ft). Retrofit factors and scope adder costs are based on the EPRI retrofit FGD cost estimating guidelines for the LSD FGD technology sorbent preparation/flue gas handling process areas and building/duct demolition costs.

2.1.4 Retrofit of Fluidized Bed Combustion and Coal Gasification

Plant life extension combined with significant emission reductions can be achieved by retrofitting fluidized bed combustion (FBC) or coal gasification (CG) with gas turbine. This can be a cost-effective approach for some utility systems if the existing turbine and other plant facilities can be reused. A qualitative evaluation of this emission control strategy was conducted under this study for each plant. A more detailed analysis was not conducted because extensive boiler/plant/system information is needed to evaluate the cost of retrofit. The economic justification for these retrofits is overwhelmingly tied to life extension and heat rate improvements rather than to emission reductions. Thus, economic comparison to the other add-on controls evaluated in this study is difficult without conducting extensive system-wide economic evaluations.

As defined in this study, retrofit of FBC and CG assumes that the existing turbine is reused as well as other plant facilities: coal receiving/handling/storage, water and wastewater treatment, solid waste disposal, etc. With FBC, it is possible to rebuild the existing boiler as was done at the Northern States Power Black Dog Unit 3 (9). However, it is assumed that a new stand-alone FBC unit or coal gasification unit with gas turbine is tied into the existing unit steam turbine.

For each plant the following criteria were reviewed to determine the potential for each boiler as a FBC or CG retrofit candidate.

Boiler Size - Boilers larger than 300 MW were not considered because of the current size of the FBC and CG units being considered and because boilers larger than 300 MW generally do not meet the other criteria that follow.

Boiler Heat Rate - Boiler heat rate has a significant economic impact on retrofit of FBC or CG, as follows: < 10,000 Btu per kilowatt hour (kWh) would not be significantly benefitted by FBC or CG; 10,000 - 11,000 Btu/kWh would be moderately benefitted; and > 11,000 Btu/kWh would be significantly benefitted.

Boiler Capacity Factor - Boilers with capacity factors significantly less than 50 percent usually are used for meeting peak demands. These boilers generally have poor heat rates and as such are low on the dispatch order.

Retrofitting FBC or CG generally will require significant downtime, and downtime penalty will be less for boilers having low capacity factors.

Unit Age - Unit age generally is an indicator of boiler size and useful remaining life. Boilers that came in service before 1950 are small (<100MW) and have poor heat rates and low capacity factors. These units are good candidates for retrofit and will significantly benefit from heat rate improvement. Additionally, the cost of FGD would be high due to economies-of-scale, capacity factors, and the short remaining life for amortization of the capital investment. Units that came in service in the 1950's are small to medium in size (100-250MW) and have moderate heat rates and low to high capacity factors. These units are moderately good candidates for retrofit depending on the cost of other control options. Units which came in service after 1960 are not likely candidates for FBC or CG retrofit because their size and remaining life would make other control options more cost-effective.

Particulate Control Performance - Because of increasingly stringent particulate and SO_2 emission limitations related to State Implementation Plans, many boilers have been retrofitted with new particulate controls capable of meeting particulate emission standards while firing low sulfur coals (<1% sulfur). These boilers may already be firing low sulfur coals, or the retrofit particulate controls were designed for firing low sulfur coals. As such, these boilers are good candidates for coal switching/cleaning and less likely candidates for retrofit of FBC or CG unless fuel price differentials or stringent SO_x/NO_x emission regulations eliminate coal switching/blending as a feasible SO_x control option.

SO_x/NO_x Emission - Many older boilers are high emitters of SO_x and NO_x, and, depending on the compliance flexibility that acid rain regulation allows (regional, state, plant, boiler), significant reduction may be required. If these boilers are difficult to retrofit for conventional and low cost SO_x/NO_x controls, retrofit of FBC or CG may become necessary to extend the life of the boiler and meet SO_x/NO_x emission levels economically. For example, many 1950's cyclone boilers have high NO_x and SO_x emission rates with moderate to high capacity factors and may be difficult retrofits for conventional SO_x/NO_x controls.

2.1.5 NO_x Controls

Three types of combustion modification NO_x control technologies were evaluated under this study. Low NO_x combustion (LNC) was evaluated for all dry bottom boilers with application of low NO_x burners (LNB) on wall-fired units and overfire air (OFA) on tangential-fired units. For wet bottom boilers, natural gas reburn (NGR) was evaluated because the application of LNB was not feasible and the application of OFA was not considered to give low enough emission rates.

Retrofit difficulty for the low NO_x combustion technologies was addressed by estimating NO_x reduction performance of LNB and OFA. Insufficient information was available to do the same for NGR. As discussed below, a qualitative assessment of each dry bottom boiler was made and a NO_x reduction performance of low, medium or high was assigned. For NGR a NO_x reduction of 50 percent was assumed for all wet bottom boilers.

Selective catalytic reduction (SCR) was evaluated for all boilers and is the only demonstrated control method for achieving very low emission levels. Two process configurations were evaluated: high dust and tail-end. The high dust retrofit requires the catalytic reactor to be located after the economizer, and the tail-end system is located before the chimney. Only one option was evaluated for each boiler, and the high dust system was applied only when space was not available for application of a tail-end system. This was done to minimize the cost of unit downtime and to minimize catalyst costs.

Retrofit difficulty for SCR was based on site access/congestion and underground obstructions. For the tail-end system, flue gas duct runs and duct/building demolition scope adders were developed for input to the IAPCS models.

2.1.5.1 Low NO_x Burners and Overfire Air--

For these controls, there are a number of site-specific factors that affect NO_x emissions from retrofit utility controls. Some of these are listed in Table 2-2. This table includes boiler characteristics, coal

TABLE 2-2. SITE-SPECIFIC PARAMETERS AFFECTING NO_x EMISSIONS FROM RETROFIT UTILITY COMBUSTION MODIFICATION CONTROLS

Boiler Characteristics	- Service Date - Manufacturer - Size (MW) - Heat Input (Btu/hour) - Location
Coal Characteristics	- Heating Value - Composition (N, O, H_2O, S, Ash, wt. %) - Ash Fusion Temperature - Ash Slagging/Fouling Indices - Volatility - Variability
Furnace Design	- Firing Type - Volume - Depth - Nose/Top Burner Row Distance - Gas Velocity
Burner Design	- Number - Spacing - Size
Boiler Operation Auxiliaries	- Excess Air - ESP Ash Unburned Carbon - Primary Air/Coal Ratio - Furnace Exit Temperature/Attemperation Margins - Windbox P - Excess Fan Capacity - Slagging/Fouling (reported) - Operating Mode (i.e., Base, Cycling, Peaking, etc.)

characteristics, furnace design, burner design, and boiler operating and auxiliary equipment.

Some of the factors in table 2-2 were used as gross surrogates for other detailed factors in lieu of available data for a given unit. For example, the coal type, mine location, heating value, and sulfur and ash contents were used as a gross surrogate in the absence of detailed coal ash slagging/fouling data. NO_x emissions generally increase with increasing fuel nitrogen content. However, coal nitrogen contents vary from only about 1-2 weight percent. Coal oxygen content has a much greater variation (approximately 5-15 weight percent) and increases the conversion of fuel-bound nitrogen to NO_x.

Coal ash fusion temperature (which can be predicted to a certain extent by slagging and fouling indices) also affects NO_x emissions. Slagging coals limit the range of acceptable boiler operating conditions and resulting furnace exit gas temperatures. Ash fusion temperatures are further lowered in the reducing atmospheres associated with low NO_x burners or overfire air systems. These staged combustion systems can alter the furnace thermal profile, potentially increasing furnace exit gas temperatures and slagging problems.

In addition to the boiler and coal characteristics, the furnace design also has a great effect on NO_x emissions. The furnace firing type (or orientation) is a general indicator of overall NO_x emission with tangential furnaces having the lowest NO_x emissions followed by (in order of increasing emissions) front wall-fired, opposed wall-fired, and cyclone and other wet bottom furnaces. Wall-fired units equipped with cell burners generally exhibit much higher NO_x emissions than those with circular burners. Low NO_x burners are not applicable to cyclone furnaces due to the high turbulence and excess air requirements of a cyclone furnace.

The furnace size and dimensions also affect NO_x emissions, since larger furnaces (relative to the boiler heat input) generally exhibit lower NO_x emissions. Also, larger furnaces are more amenable to retrofitting low NO_x combustion controls both from wall space/strength considerations and adequate residence time for ensuring complete combustion.

The arrangement of burners on the furnace wall(s) can also affect NO_x emissions of retrofit controls. The number and spacing of burners influence the problems of coal/air distribution among burners and the degree of interaction and mixing between flames. NO_x emissions are generally increased by these problems.

Finally, the boiler operation and auxiliary equipment characteristics can also affect NO_x emissions. NO_x emissions generally increase with total excess air. Also, NO_x emissions tend to increase with the fraction of the total combustion air introduced to the furnace as primary air (serving to dry the coal in the pulverizers and transport it to the burners). Combustion staging can increase furnace exit gas temperatures and superheat temperatures, thus increasing attemperation requirements. Some low NO_x burners will have higher pressure drops, and overfire air systems will alter windbox draft characteristics due to combustion air diverted from the windbox to the OFA drafts. These effects can require additional fan capacity.

Based on the above discussion, it is clear that there are a number of site-specific characteristics that can increase NO_x emissions and limit the performance of retrofit low NO_x combustion controls. Data for many of the parameters listed in table 2-2 and others that may affect NO_x emissions are not readily available. Therefore, retrofit NO_x combustion control performance and cost effectiveness estimates for the Ohio/Kentucky/TVA utility plants analysis will be presented as ranges. The NO_x reduction performance ranges are as follows:

	NO_x Emission Reduction (percent)	
	Minimum	Maximum
Low NO_x Burner	20	50
Overfire Air	10	30

These performance ranges were applied only to those boiler types for which the controls are applicable (e.g., low NO_x burners for dry bottom wall-fired units and overfire air for tangentially-fired units).

2.1.5.2 Natural Gas Reburning--

Natural gas reburning (NGR), although not as commercially developed as the other NO_x combustion technologies, is included in this analysis.

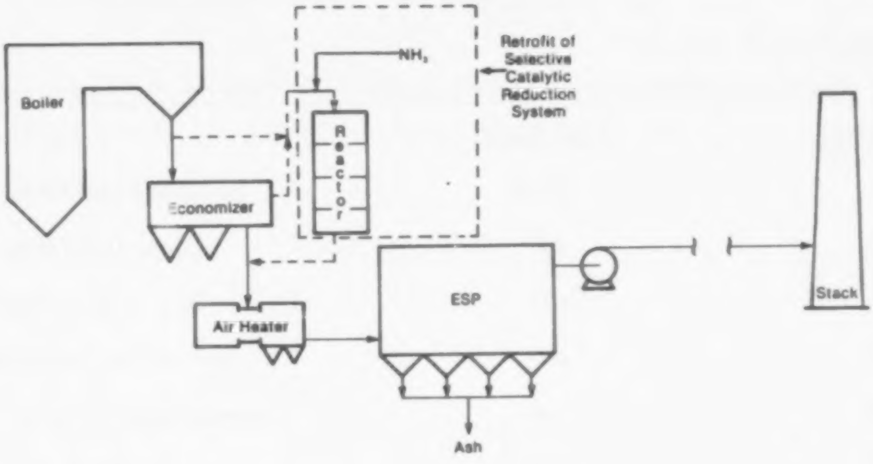
Inclusion of NGR in the study provides a moderate level NO_x control (relative to SCR) for those boilers for which low NO_x burners are inapplicable (e.g., cyclone furnaces). The NO_x reduction performance of natural gas reburning would be affected by some of the same factors discussed in the previous section for LNC. However, due to the lack of commercial demonstration performance data, a single estimate of 50 percent NO_x reduction was used in this study.

To achieve 50 percent NO_x reduction, it is estimated that approximately 15 percent of the boiler heat input would be injected into the upper furnace as natural gas. Capital costs include the installation of natural gas and overfire air injection ports into the upper furnace, reburn gas supply piping, and controls.

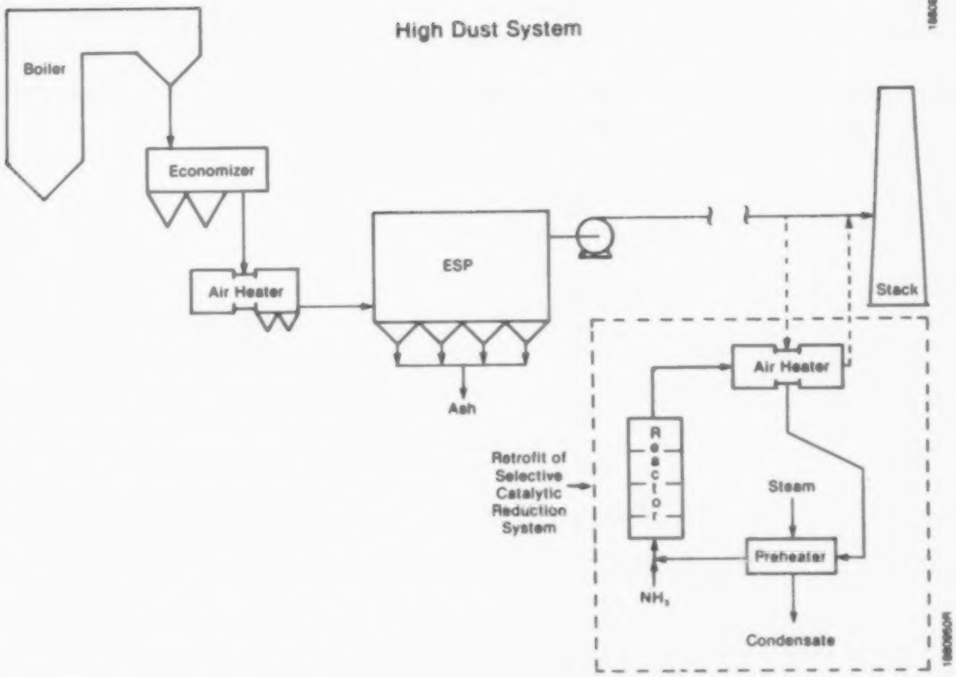
2.1.5.3 Selective Catalytic Reduction--

The major equipment items for a SCR system include the catalyst, ammonia system, controls, air preheater modifications or flue gas reheater, ductwork, and fan. The catalyst volume is based on the flue gas flow rate and the required NO_x reduction percentage. The correlation between catalyst residence time (i.e., catalyst volume/flue gas flow rate) and NO_x reduction performance is based on SCR system vendor design data (10). The SCR equipment cost estimates were developed from recent EPRI (11) and EPA (12) studies.

Two SCR system configurations were evaluated and are shown on figure 2-3. The high dust system configuration requires that the catalytic reactor be placed in the flue gas path after the economizer and before the air heater to take advantage of the high flue gas temperature (~600-700^{o}F). The catalytic reactor for a tail-end system would be located in the flue gas path just before the flue gas enters the chimney. This system requires that the flue gas be reheated to 600-700 ^{o}F. Table 2-3 summarizes the pros and cons of the two configurations. Both types of systems are being used in Japan and Germany. For this study, it was assumed that when space was available, the tail-end configuration would be used. This configuration minimizes unit downtime and replacement power costs and maximizes catalyst



High Dust System



Tail-End System

Figure 2-3. Possible SCR configurations.

TABLE 2-3. TRADE-OFFS ASSOCIATED WITH HIGH DUST/TAIL-END SCR SYSTEMS FOR COAL-FIRED UTILITY BOILERS

	High Dust	Tail-End
Boiler downtime (months)	6-12	1-2
Boiler modifications	Yes	No
Economizer bypass	Yes	No
Air preheater refitting	Yes	No
Precipitator reinforcement	Yes	No
SCR flyash removal	Yes	No
SCR system access/congestion	High	Low-moderate
Catalyst		
Life (hours)	~12,000	~20,000
Type	Honeycomb or plate	Pellet
Catalyst cost	Higher, due to larger volume/ shorter life	Lower, due to less volume/ longer life
Reheat system	No	Yes
Energy penalties		
Reheat	No	Yes
Exchanger pressure drop	No	Yes
Catalyst cleaning air	Yes	No
Combined boiler application	No	Yes
Coarse dust preseparator	Yes	No
NH_3 Slip	Higher	Lower

life. This system also lends itself to combining smaller units into one system, thereby obtaining economies-of-scale benefits.

The method used to develop retrofit factors and scope adders for SCR is similar to the FGD methods. Scope adder costs considered are as follows:

- duct and building demolition,
- new duct work,
- new roads and replacement of demolished facilities, and
- new air heater or flue gas reheater.

The EPRI FGD retrofit guidelines were used to develop costs for the first three items. New roads and replacement of facilities were handled as increases in general facilities. New air heater and flue gas reheater costs are based on a vender quote for a 500MW plant and scaled by a 0.6 factor (13).

Access/congestion and underground obstruction factors were applied to the catalytic reactor area. The EPRI FGD retrofit guideline factors for the SO_2 and flue gas handling area were used. The scope adders and retrofit difficulty factor were input to IAPCS to generate the site-specific retrofit cost estimates.

2.2 IAPCS COST MODEL

Technology assumptions were assigned to the acid rain technologies selected for evaluation. These assumptions are presented below for the technologies in order of pre-, in situ, and post-combustion emission control technologies. A number of the process design assumptions are "nominal" in that they vary from plant to plant and, in some cases, from boiler to boiler, in accordance with site-specific characteristics.

2.2.1 Physical Coal Cleaning (PCC)

The absence of coal washability data for the plants visited required that a number of process and cost assumptions be established in order to estimate cleaned coal characteristics and associated cost and performance estimates. Cleaned coal characteristics were estimated using the set of six standard coals built into the PCC technology module of IAPCS. The coals of particular relevance to this effort were the Ohio high sulfur and the West Virginia low sulfur coals. The coal washability characteristics of these "standard" coals were applied to the plants based on coal consumption patterns as reported in the FERC Form 423 (13). The associated costs were assigned on a dollars-per-ton fuel premium accounting for the cost to own and operate the PCC plant by the coal mine. A summary of the PCC technology assumptions is presented in table 2-4.

2.3.2 Coal Substitution/Blending (CS/B)

A coal substitution/blending strategy was developed for the plants by analyzing their current coal usage patterns. For plants in Ohio, two predominant low sulfur coals emerged--a West Virginia bituminous coal and an eastern Kentucky bituminous coal. For plants in Kentucky, Tennessee, and Alabama, the two predominant coals also originated from West Virginia and eastern Kentucky. The cost and characteristics of these coals were developed from the FERC Form 423 for 1985. The proximate analyses associated with these "composite" low sulfur replacement coals are presented in table 2-5. The costs associated with these coals with respect to the coals consumed at the various plants in 1985 are presented in table 2-6.

Particulate control impacts were evaluated by considering the altered particulate loading and particulate resistivity associated with the replacement coal as compared to original conditions. Electrostatic precipitator upgrades were costed by calculating additional plate area in the presence of SO_3 gas conditioning to maintain current PM emission rates. These costs were estimated using the ESP module of IAPCS.

The final step was to estimate the capital and annual operating costs that would be required to switch to lower sulfur coals and not have a significant system derate. Four coal fuel cost differentials (premiums) were used in this analysis. The first fuel cost differential (FCD) was based on the current coal prices as shown in table 2-6. Then, premiums of $5 and $15 per ton were used to span the range of fuel cost increase associated with low sulfur coal demand. These costs do not include the cost

TABLE 2-4. PCC TECHNOLOGY ASSUMPTIONS

Reference Coals	OH (Jefferson)	WVA (Logan)
ROM		
Btu/lb	11,922	12,058
Ash, %	13.0	16.6
S, %	3.43	0.89
H_2O, %	5.0	3.5
Cleaned		
Btu/lb	12,845	13,611
Ash, %	6.6	4.6
S, %	2.74	0.83
H_2O, %	4.4	5.4
Wt. recovery, %	85	82.5
Btu recovery, %	91	95
Cost		
Capital charges, $/ton raw	1.05	1.22
O&M, $/ton raw	2.80	2.80
Total annual, $/ton	3.85	4.02
Plant Assignments		
Burger	X	
Conesville	NA[a]	NA
Muskingum River	NA	NA
Sammis	X	
Stuart		X
Big Sandy		X
Brown		X
Colbert		X
Cumberland	NA	NA
Johnsonville		X
Paradise	NA	NA
Smith		X

[a] Not applicable. PCC currently practiced at plant.

TABLE 2-5. PROXIMATE ANALYSES OF REPLACEMENT LOW SULFUR COALS

Coal	Rank	Btu/lb	A%	M%	S%	VM%	FC%
Ohio							
West Virginia (southern)	Bituminous	12,058	16.6	9.6	0.9	25.8	48.0
Kentucky (eastern)	Bituminous	12,554	8.8	7.6	0.9	29.3	54.4

TABLE 2-6. COST OF EXISTING AND REPLACEMENT LOW SULFUR COALS

Plant	Current Coal, \$/ton[a]	Replacement Coal	Replacement Coal, \$/ton[a]	Coal Premium, \$/ton[a]
Burger	32.07	EKy	46.62	14.55
Conesville	37.83	WVa	44.89	7.06
Muskigum River	37.97	WVa	44.89	6.92
Sammis	34.45	WVa	44.89	10.44
Stuart	43.60	EKy	46.62	3.02
Big Sandy	35.93	WVa	50.23	14.30
Brown	33.83	EKy	42.07	8.23
Colbert	44.08	EKy	40.78	3.08
Johnsonville	31.62	EKy	42.07	10.45
Paradise	26.70	EKy	40.78	14.08
Smith	37.27	EKy	42.07	4.80

[a] Mid-1985 dollars.

impact of additional coal receiving/storage/handling facilities, if needed, and the cost impact of boiler derate due to pulverizer capacity and boiler fouling, slagging, and erosion.

2.2.3 Low NO_x Combustion (LNC)

Low NO_x combustion was applied solely to pulverized coal dry bottom boilers. Two process variations were considered: overfire air (OFA) and low NO_x burner (LNB). Overfire air was applied to PC, tangentially-fired boilers (i.e., corner-fired boilers). Low NO_x burners were applied to PC, wall-fired boilers (i.e., front or opposed). The NO_x reduction performance assigned ranged from 20 to 50 percent for LNB and 10 to 30 percent for OFA. The removal efficiencies were adjusted from site to site to reflect specific design and operating conditions as discussed in Section 2.1.5. A summary of the LNC technology cost/performance assumptions is presented in table 2-7.

2.2.4 Natural Gas Reburning (NGR)

Natural gas reburning was added to the technology mix during the course of the research program as an alternative to in situ low NO_x combustion technology for those boilers that could not accommodate the LNC processes: cyclone and wet bottom wall-fired boiler. In addition, a number of top-fired boilers were found in the Ohio population (e.g., Burger boilers 1 through 6). Although boilers of this firing type are rare (i.e., an archaic firing configuration relegated to small, old boilers), they also cannot accept the newer vintage of low-NO_x burner assemblies.

One NGR process variation was evaluated, and that was the injection of natural gas into the upper radiant section of the boiler. The natural gas feed rate was set at 15 percent of the coal-feed (based on heat input). The nominal NO_x reduction was originally set at 50 percent because of performance uncertainties at the commercial scale (developers claim reductions in the 60 to 75 percent range). Process scope items include boiler combustion modifications and provision of gas feed to the plant if not currently available. Cost elements include a fuel cost differential (between natural gas and coal) of $2 per million Btu and credits for savings

TABLE 2-7. LNC TECHNOLOGY ASSUMPTIONS

Processes	OFA LNB
Boiler application	Pulverized coal:dry bottom
Process application:	
OFA	Tangentially fired
LNB	Wall-fired (front as opposed)
Process description:	
OFA	One port per row of
LNB	One replacement burner per existing burner
Boiler modifications	Boiler tube, windbox, and pressure part
NO_x control, percent:	
OFA	25 (nominal) 10-30 (actual)
LNB	50 (nominal) 20-50 (actual)

in coal pulverizer operation, solid waste disposal, and operating and labor supervising. A summary of the NGR technology assumptions is presented in table 2-8.

2.2.5 Furnace Sorbent Injection (FSI)

The basic process configuration selected for evaluation involves the injection of calcitic hydrate into the upper radiant/lower convective section of the furnace. Boilers having ESPs with a specific collection area of less than 220 $ft^2/10^3$ ACFM were assumed not to be upgradable and these boilers were not evaluated for FSI. The calcitic hydrate is assumed delivered to the plant in a prepared form (i.e., ready for injection). The sorbent is injected at a rate fixed by a calcium-to-sulfur stoichiometric (Ca/S) ratio of 2.0 to 1.0. Two calcium utilization (CaU) cases were evaluated: 25 percent (base case) and 35 percent. These CaUs were assumed to provide SO_2 captures of 50 and 70 percent, respectively. The only PM control configuration evaluated was reuse of the existing ESP. The ESP operation was upgraded by incorporating spray humidification as a gas conditioning process into the configuration. Where necessary, an ESP "tune up" was provided through the addition of gas distribution vanes and baffles to reduce leakage. Boiler modifications were provided in every case and existing wet fly ash handling systems were converted to dry systems where necessary. A summary of the FSI technology assumptions is presented in table 2-9.

2.2.6 Selective Catalytic Reduction (SCR)

Selective catalytic reduction, like NGR, was also added to the technology mix during the course of the research program as a high efficiency NO_x control option that can bring high NO_x emitting boilers in compliance with proposed NO_x acid rain emission standards. Selective catalytic reduction was applied to all coal-fired boilers evaluated. A summary of the SCR technology assumptions is presented in table 2-10.

Two SCR process variations were evaluated. In the first configuration, the SCR reactors are placed in the "hot side" of the boiler--between the

TABLE 2-8. NGR TECHNOLOGY ASUMPTIONS

Process	NG Substitution
Design Configuration:	
NG substitution, %	15
Injection point	Upper furnace
Gas service to plant	5 miles
Process application	All boiler firing types
NO_x control, percent	50
SO_2 control, percent	15
PM control, percent	15
FCD, $/million Btu	2.00

TABLE 2-9. FURNACE SORBENT INJECTION TECHNOLOGY ASSUMPTIONS

Process	Calcitic hydrate
Design configuration:	
Sorbent preparation	Prepared off site
Injection point	Upper furnace
PM control	ESP upgrade
Waste handling	Dry
Process design:	
Ca/S ratio	2:1
Boiler quench rate, °F/S	700
CaU, %	25 and 35
SO_2 capture, %	50 and 70
Gas conditioning	Spray humidification
ESP upgrade	Tune up for ESPs < SCA
Process application	All boiler firing types except roof

TABLE 2-10. SCR TECHNOLOGY ASSUMPTIONS

Processes	High-Dust Tail-End
Design configuration	
Ammonia preparation	NH_3 storage and injection
Reactors	2 ($\leq$500 MW) 3 (750 MW) 4 ($\geq$1,000 MW)
Flue gas handling	Gas ductwork
Waste disposal	Conventional
Process design	
NH_3 stoichometric ratio	0.87
NH_3 slip, %	2
NO_x control, %	80
Catalyst life, year	1 - High-Dust 2 - Tail-End
Process application	Existing cold-side PM controls
Air heater modification	Corrosive resistant heater elements and additional surface area.
-or-	
Flue gas reheater.	Flue gas to flue gas heat exchange and steam or duct burner reheaters.

economizer and air preheater. This configuration is upstream of the particulate control device and is referred to as the high dust system. In the second configuration, the SCR reactors are placed in the cold side of the boiler--before the stack and downstream of other emission control systems. This configuration is referred to as the tail-end system. The basic SCR system comprises four process areas--ammonia preparation, reactors, flue gas handling, and air heater modifications or flue gas reheater. The target NO_x control efficiency was established at 80 percent based on an ammonia (NH_3) stoichiometric ratio of 0.87. The NH_3 "slip" (i.e, unreacted NH_3) was set a 2 percent for these conditions. Catalyst life, which is the primary cost driver, was set at one year. However, based on the Japanese and German commercial experience, catalyst life of three to five years is most likely to be achieved at many U. S. units. A three-year catalyst life reduces the annual cost of SCR by forty to fifty percent.

The spent catalyst was assumed to be disposed of as a non-hazardous waste. Any lost generation capacity associating with extended unit outage for installation of the SCR system was not accounted for.

2.2.7 Lime Spray Drying (LSD)

Two process variations were evaluated: LSD with conventional spray dryer absorber and LSD with duct spray drying. The latter variation was added during the course of the research program in response to technology developments involving a low cost retrofit LSD process that could achieve modest SO_2 captures for high sulfur coal applications. The design and performance assumptions associated with the LSD-spray dryer absorber (LSD FGD) configuration also underwent significant modification during the course of the project. These modifications were made in response to technology developments to LSD high sulfur coal applications for ESP and fabric filter (FF) configurations. Research results reported by TVA and Research-Cottrell revealed higher SO_2 captures than previously assumed from the extrapolation of results from low sulfur coal. These design conditions are addressed in the technology assumptions described below.

For both processes, the external lime stoichiometric ratio was set at 1.4, the recycling ratio was set at 50 percent, the solids content of the recycle slurry was set at 35 percent, the solids content of the fresh lime slurry feed was set at 25 percent, the saturation temperature approach was set at 20^{o}F, and additional ESP insulation was provided. Sulfur dioxide captures were adjusted as follows:

- The nominal SO_2 removal for LSD-FGD with a FF in the configuration was set at 86 percent. With an ESP configuration, the nominal SO_2 removal efficiency was set at 70 percent. These nominal values represent maximum SO_2 removals achieved under optimal conditions. The actual values predicted by the model are a function of flue gas physical conditions and composition.
- The nominal SO_2 removal for LSD-FGD was set at 50 percent across the entire system for ESP configurations. Additional SO_2 removal was provided with the FF configuration because of greater SO_2 capture across the FF. The actual values predicted by the model are a function of flue gas physical conditions and composition.

A summary of the LSD technology assumptions is presented in table 2-11.

2.2.8 Gas Conditioning

Gas conditioning, unlike the other technologies described in this section, is not an emission control technology per se. Instead, it functions as an auxiliary technology in that it assists the performance of another emission control technology in the configuration. In this case, the dependent control technology is an electrostatic precipitator (ESP). Gas conditioning was incorporated into the control configuration where the loading or the particle resistivity of the PM in the inlet gas stream to the existing ESP was altered. This occurred for the coal supply options (PCC and CS/B) and the sorbent injection technologies (FSI, and LSD/DSD with ESP reuse).

Two process options were evaluated--sulfur trioxide (SO_3) conditioning and spray humidification. The former was applied to the coal supply options and the latter to FSI, DSD, and LSD. For SO_3 conditioning, a residual SO_3 concentration of 5 ppm was maintained in the flue gas stream. For spray

TABLE 2-11. LSD TECHNOLOGY ASSUMPTIONS

Processes	Spray dryer absorber Duct spray drying
Design configuration	SDA-existing ESP (upgrade) SDA-replacement FF DSD-existing ESP (upgrade) DSD-replacement FF
Process design:	
Stoichiometric ratio, Ca/S	1.4
Recycle ratio, %	50
Recycle slurry solids, %	35
Lime slurry solids, %	25
Saturation approach, °F	20
Nominal SO_2 captures, %	73-86 (SDA) 50-68(DSD)
Process application	All boilers

humidification, a saturation approach temperature of 160°F was maintained in the flue gas stream.

A summary of the GC technology assumptions is presented in table 2-12.

2.2.9 Electrostatic Precipitator (ESP)

The electrostatic precipitator was evaluated in a manner different from the other emission control technologies. Whereas the other emission control technologies were evaluated as additions to the plant's control configuration to remove SO_2 and/or NO_x, the ESP was evaluated as a technology already in place with potential performance consequences based on upstream impacts. In other words, the existing ESP was upgraded to restore its original performance prior to the addition of upstream control technologies.

The performance of the existing ESP is subject to the same impacts manifested by the technologies described for gas conditioning in Section 2.2.8. Two ESP upgrade options were considered--SO_3 conditioning for the coal supply options and spray humidification for FSI, DSD, and LSD. In the former, SO_3 conditioning was exercised to reduce the incremental plate area associated with increased PM loading and altered particle resistivity. This was done with the aid of temperature-resistivity relationships developed for EPA (14). The effect of the SO_3 with respect to minimizing incremental plate area was set at 25 percent, based on the results of a literature search by PEI (15). In the latter, spray humidification and an ESP "tune up" were exercised to reduce the incremental plate area associated with the solids loading and altered particle resistivity. This was done with the aid of cost and performance relationships directed by Environmental Protection Agency Air and Energy Engineering Research Laboratory (EPA-AEERL).(16) For all ESP evaluations, the total collection area of the existing ESP, represented as specific collection area (SCA) in terms of ft^2 of plate area per 1000 ft^3 of actual gas flow, was used as the basis to estimate ESP impacts.

TABLE 2-12. GC TECHNOLOGY ASSUMPTIONS

Processes	SO_3 conditioning Spray humidification
Design configuration:	
PCC and CS	SO_3-ESP
LIMB and LSD	SH-ESP
Process design:	
Residual SO_3, ppm	5
Saturation approach, °F	160
Process application	
SO_3 conditioning	All existing ESP-equipped boilers
Spray humidification	All existing ESP-equipped boilers

2.2.10 Fabric Filter (FF)

A fabric filter was also evaluated in a manner similar to that described above for ESP. Namely, an FF was provided as a replacement or alternative collection device for the existing ESP. This option was considered only for the LSD FGD and DSD. For these processes, the FF provided a significant improvement in total system SO_2 removal through the incremental capture of SO_2 across the filter cake. As noted in the discussion of LSD technology, the downstream FF provided approximately 13 percentage points of additional SO_2 capture with FF as opposed to an ESP.

2.2.11 Flue Gas Desulfurization (FGD)

Four process variants were evaluated: conventional limestone slurry, conventional lime slurry, adipic acid-promoted limestone slurry, and magnesium oxide-promoted lime slurry. The "target" SO_2 removal efficiency was established at 90 percent for all cases in accordance with our philosophy of evaluating each technology at its best removal capability. The target SO_2 removal was achieved by optimizing the reagent stoichiometric ratio and absorber liquid-to-gas (L/G) ratio. Pertinent process design parameters included the use of vertical spray tower absorbers, primary and secondary solid dewatering via thickener and vacuum filter (60 percent solids waste slurry), and waste treatment and disposal via chemical fixation and off-site landfill disposal. All cases were evaluated under a full scrubbing scenario, which implied the use of reheat provided by an in-line steam reheater. The number of absorber towers was varied with boiler size and one spare tower was provided. "Standard" sparing practice was followed for all other components. Three types of design strategies were considered. In the first strategy, all boilers were equipped with a complete, self-contained FGD system (provided that this made sense in terms of boiler size and spatial constraints). In the second strategy, a number of boilers (where applicable, based on locational and spatial constraints) were equipped with "combined" FGD systems in which all process areas were shared (i.e., the flue gas from several boilers was combined and treated as a single larger boiler). In the third strategy, a low-cost FGD system was applied at all plants. In this strategy, smaller boilers were combined, minimizing absorber costs. Organic acid additives were used, and absorber size was increased to minimize the number of towers needed. A summary of the FGD technology assumptions for conventional FGD is presented in table 2-13.

2.2.12 Waste Disposal

The disposal of solid waste was handled in a consistent manner for all plants. The only variation in this strategy concerned the haul distance of the waste from the plant to the landfill. All solid waste products were disposed of in an off-site landfill. Waste treatment was provided for FGD technology in the form of chemical fixation of the dewatered waste slurry, using lime and fly ash additives. No chemical treatment was applied to the dry waste producing processes; all material was collected as is and disposed in off-site landfills.

2.3 ECONOMIC AND FINANCIAL ASSUMPTIONS

At the outset of the NAPAP Task Group I effort, a decision was made to use economic and financial data consistent with accepted industry practices. The accepted standard for the electric utility industry is published in the EPRI's Technical Assessment Guidelines (TAG). The EPRI TAG provides the economic factors and financial data on which the cost estimating procedures used in the electric utility industry are based. These procedures were adopted for the NAPAP Task Group I effort. At the outset of the project, the 1981 edition of the EPRI TAG was available as the primary source of cost information (17). Subsequent supplements issued by EPRI updating key economic and financial data were received and used as appropriate (18). In December 1986, the fifth (and latest) edition of the EPRI TAG was used in calculating all the cost information reported herein (6). It should be noted that the preliminary draft estimates generated and reviewed with the project participants and industry were prepared under the fourth edition EPRI TAG premises. Hence, the cost information reported here reflects changes in economic and financial assumptions as contained in the current

TABLE 2-13. FGD TECHNOLOGY ASSUMPTIONS

Processes	Limestone Lime Promoted lime/limestone
Design configuration	
Absorber	Vertical spray tower
Reheat	In line steam
Draft loss	ID booster fans
Solids treatment	Dewatered/fixation/landfill
Design strategy	Self-contained system Multiple boiler combined system Low cost system
Process design[a]	
Nominal stoichiometric ratio	Limestone - 1.4 Promoted limestone-107 Promoted lime-1.05
Nominal L/G ratio	Limestone-110 Lime-80 Promoted lime/limestone-70
Number of absorbers	<100 MW = 1 100-250 MW = 2 250-500 MW = 3 500-750 MW = 4 750-1000 MW = 5 >1000 MW = 6
Number of spare absorbers	1

[a] For self-contained design strategy.

EPRI TAG. Table 2-14 presents a comparison of the old values with the new values.

The following is a brief overview of the economic and financial assumptions of the EPRI TAG as applied in this stage.

1. Cost-estimating premises adhere to the cost methodology described in chapter 3 of 1986 EPRI TAG.
2. A set of nominal indirect capital cost factors was assigned to each technology evaluated in accordance with the EPRI TAG. These values were varied in accordance with site-specific conditions. The nominal settings are presented in table 2-15 for comparative purposes.
3. Allowance for funds during construction (AFDC) is estimated by adjusting the total plant cost by an allowance factor (AF) that is a function of the idealized construction period and economic parameters. Current assumptions per 1986 EPRI TAG are also listed in table 2-15.
4. For annual operating costs, the unit costs for consumables per the EPRI TAG are summarized in table 2-16.
5. Total annual maintenance costs are estimated per the 1986 EPRI TAG as a percentage of installed capital cost depending on the nature of the processing conditions and the type of design. A summary of the factors assigned to the various technologies is presented in table 2-17.
6. Economic premises for existing electric power generating plants were updated by EPRI and released as a supplement issued May 1, 1983. Revised schedules were published for book life, tax life, and levelization factors. For power plants in operation before January 1, 1979, IRS Code Section 169 allows 5-year tax depreciation of new identifiable pollution control facilities completed or acquired after December 31, 1982. This depreciation schedule is applied on a straight-line basis. Book life of retrofitted equipment is equal to the years of remaining life of

TABLE 2-14. COMPARISON OF OLD AND NEW EPRI TAG VALUES

"Old" Values

CAPITAL AND FINANCIAL STRUCTURE

Type of Security	Percent of total	Current dollar Cost	Current dollar Return
Debt	50	11.0	5.5
Preferred	15	11.5	1.7
Common stock	35	15.3	5.3
Discount rate %/yr			12.5

Inflation rate:	6%/yr
Federal and state income tax rate:	50.0%
Investment tax credit:	8.0%
Property taxes and insurance:	2.0%

UNIT COST DATA

Item	January 1985 value	Units
Operating labor	19.70	$/person hour
Water (river)	0.60	$/1000 gal
Lime	65	$/ton
Limestone	15	$/ton
Land	6,500	$/acre
Disposal Charges		
Sludge	13	$/ton (dry basis)
Dry, granular solids	6.5	$/ton
By-Product Credits		
Sulfuric acid	50	$/ton
Sulfur	75	$/long ton
Ammonia (anhydrous)	150	$/ton
Special Items		
Electric power (in plant)	3.5[a]	¢/kWh
Steam (in plant)		
0-70 psia	2.50[a]	$/1000 lb
70-250 psia	3.10[a]	$/1000 lb
250-2400 psia	4.90[a]	$/1000 lb
LEVELIZATION FACTORS		
O&M	1.452	
Carrying charges, %	16.6	

"New" Values

CAPITAL AND FINANCIAL STRUCTURE

Type of Security	Percent of total	Current dollar Cost	Current dollar Return
Debt	50	11.0	5.5
Preferred	15	11.5	1.7
Common stock	35	15.3	5.3
Discount rate %/yr			12.5

Inflation rate:	6%/yr
Federal and state income tax rate:	38.0%
Investment tax credit:	0.0%
Property taxes and insurance:	2.0%/yr

UNIT COST DATA

Item	January 1985 value	Units
Operating labor	19.70	$/person hour
Water (river)	0.60	$/1000 gal
Lime	65	$/ton
Limestone	15	$/ton
Land	6,500	$/acre
Disposal Charges		
Sludge	9.25	$/ton (dry basis)
Dry, granular solids	8.0	$/ton
Gypsum disposal	4.75	$/ton
By-Product Credits		
Sulfuric acid	50	$/ton
Sulfur	75	$/long ton
Ammonia (anhydrous)	150	$/ton
Special Items		
Electric power (in plant)	5.0	¢/kWh
Steam (in plant)		
0-70 psia	2.85	$/1000 lb
70-250 psia	3.50	$/1000 lb
250-2400 psia	5.30	$/1000 lb
LEVELIZATION FACTORS		
O&M	1.452	
Carrying charges, %	18.0	

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[a] January 1981 value.

TABLE 2-15. NOMINAL INDIRECT COST SCHEDULE

Indirect component[a]	PCC	LNC	LIMB	NGR	SCR	LSD	DSD	ESP	FF	FGD
General facilities, %	0	10	10	10	10	10	10	10	10	10
Engineering and home office fees, %	0	10	10	10	10	10	10	10	10	10
Project contingency, %	0	15	30	15	30	15	20	15	15	15
Process contingency, %	0	10	30	10	30	15	20	10	10	10
Sales tax, %	0	0	0	0	0	0	0	0	0	0
Total, %	0	45	80	45	80	50	60	45	45	45
Royalty allowance, %	0	0	0	0	0.5	0	0	0	0	0
Preproduction costs[b]	b	b	b	b	b	b	b	b	b	b
Inventory capital[c]	c	c	c	c	c	c	c	c	c	c
Initial catalyst	0	0	0	0	0	0	0	0	0	0
Idealized construction period, yr[d]	0	1	1	1	1	3	1	3	3	3

[a] Applied to process capital except as noted.

[b] 1 month of fixed operating cost.
1 month of variable operating cost.
2 percent of total plant investment.

[c] 60-day supply of consumables.

[d] Used for estimating AFDC.

TABLE 2-16. UNIT OPERATING COSTS

Item	Value	Units	$
Operating labor[a]	19.70	$/person hour	1/85
Water (river)[b]	0.60	$/1000 gal	1/85
Lime	65	$/ton	1/85
Limestone	15	$/ton	1/85
Land	6,500	$/acre	1/85
Disposal charges[c]			
Sludge	9.75	$/ton (dry basis)	1/85
Dry, granular solids	8.00	$/ton	1/85
Wastewater (included in plant capital and operating costs)			
Byproduct credits[d]			
Sulfuric acid	50	$/ton	1/85
Sulfur	75	$/long ton	1/85
Ammonia (anhydrous)	150	$/ton	1/81
Special items[e]			
Electric power (in plant)	5.0	¢/kWh	1/85
Steam (in plant)			
0 to 70 psia	2.85	$/1000 lb	1/85
70 to 250 psia	3.50	$/1000 lb	1/85
250 to 2400 psia	5.30	$/1000 lb	1/85

[a] Based on a direct labor charge of $14.6/h plus 35 percent payroll burden.

[b] This is a raw water acquisition charge only. Intake structures, treating, and pumping costs are to be included in plant capital and operating costs.

[c] Normally, waste disposal facilities are included in plant capital and operating costs. The changes shown here are representative of off-site disposal costs for special cases where on-site disposal is not included.

[d] Byproduct storage, shipping, and marketing facilities must be included in the plant capital and operating cost if these byproduct credits are used.

[e] These special valus are to be used only in studies of limited scope which do not internally produce electricity and steam costs. The values are based on a 2400-psi coal-fired power plant.

TABLE 2-17. MAINTENANCE COST FACTORS

	PCC	LNC	LIMB	NGR	SCR	LSD	DSD	ESP	FF	FGD
EPRI schedule (percent of total process capital)	0	2	4	2	4	6	6	8	4	8

the power plant rounded off to the nearest 5-year increment. All of these items are identical in the 1986 TAG.

7. Revised financial factors for capital structure are presented in table 2-18.

8. The revised financial and economic premises significantly influence the levelization factors calculated for O&M and carrying charges. Using the revised guidelines recommended by EPRI-12.5 percent discount rate (or weighted cost of capital), 6.0 percent inflation rate (long-term average), 15-year book life (existing facility), and 5-year tax life (straight-line depreciation)--the levelization factors computed for O&M and capital carrying charges are 1.452 and 0.18, respectively.

9. All costs are presented in current dollars (i.e., the effect of escalation due to inflation is accounted for) and reflect April 1987 dollars. Capital costs are escalated using the Chemical Engineering indices.

TABLE 2-18. REVISED FINANCIAL FACTORS FOR CAPITAL STRUCTURE[a]

Type of security	Percent of total	Current dollar Cost	Current dollar Return
Debt	50	11	5.5
Preferred	15	11.5	1.7
Common Stock	35	15.3	5.3
Discount rate, percent/year (weighted cost of capital)			12.5
Inflation rate:	6%/yr (long term average)		
Federal and state income tax rate:	38%		
Investment tax credit:	0%		

[a] Capital structure based on 1984 EEI System Planning Committee Survey.

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SECTION 3

BURGER PLANT RETROFIT FACTORS AND COSTS

3.1 PLANT DESCRIPTION

The Burger Plant, owned and operated by Ohio Edison Company, is located in eastern Ohio along the Ohio River south of Wheeling, West Virginia. The plant is totally coal-fired and has a total net generating capacity of 510 MW. Figure 3-1 shows the location of the eight boilers and other auxiliary equipment. The plant is bounded to the south, the east, and partially to the west by the Ohio River. The remainder of the western side of the plant is bounded by a small quarry. To the north, the plant is bounded by a roadway and small housing development.

The plant coal storage and handling area is located along the eastern side of the site and is bounded by the river and the plant proper. Coal is received by barge from local mines and is unloaded by a clamshell unloader. From the unloader, it is conveyed 75 yards to the stacker which is located at the center of the coal storage pile. The stacker can unload onto either an active storage pile which is located over the only bunker or onto one of two inactive piles located north and south of the bunker. From the bunker, the coal is conveyed to a breakhouse where it is fed to another conveyor for transport to the eastern end of the plant.

The first six boilers are paired to three steam turbines and run from east to west with boilers 1 and 2 being the easternmost pair. The turbines for boilers 1-6 are located to the north of each boiler pair. Boilers 7 and 8 continue the progression to the west, but each feeds a separate turbine. Table 3-1 presents the key design and operating data obtained from EIA Form 767 and the plant visit.

Boilers 1-6 and their accompanying turbines 1-3 went into service between 1944 and 1950. Boilers 7 and 8 and their accompanying turbines 4 and 5 went into service in 1955. The generator capacities in order of

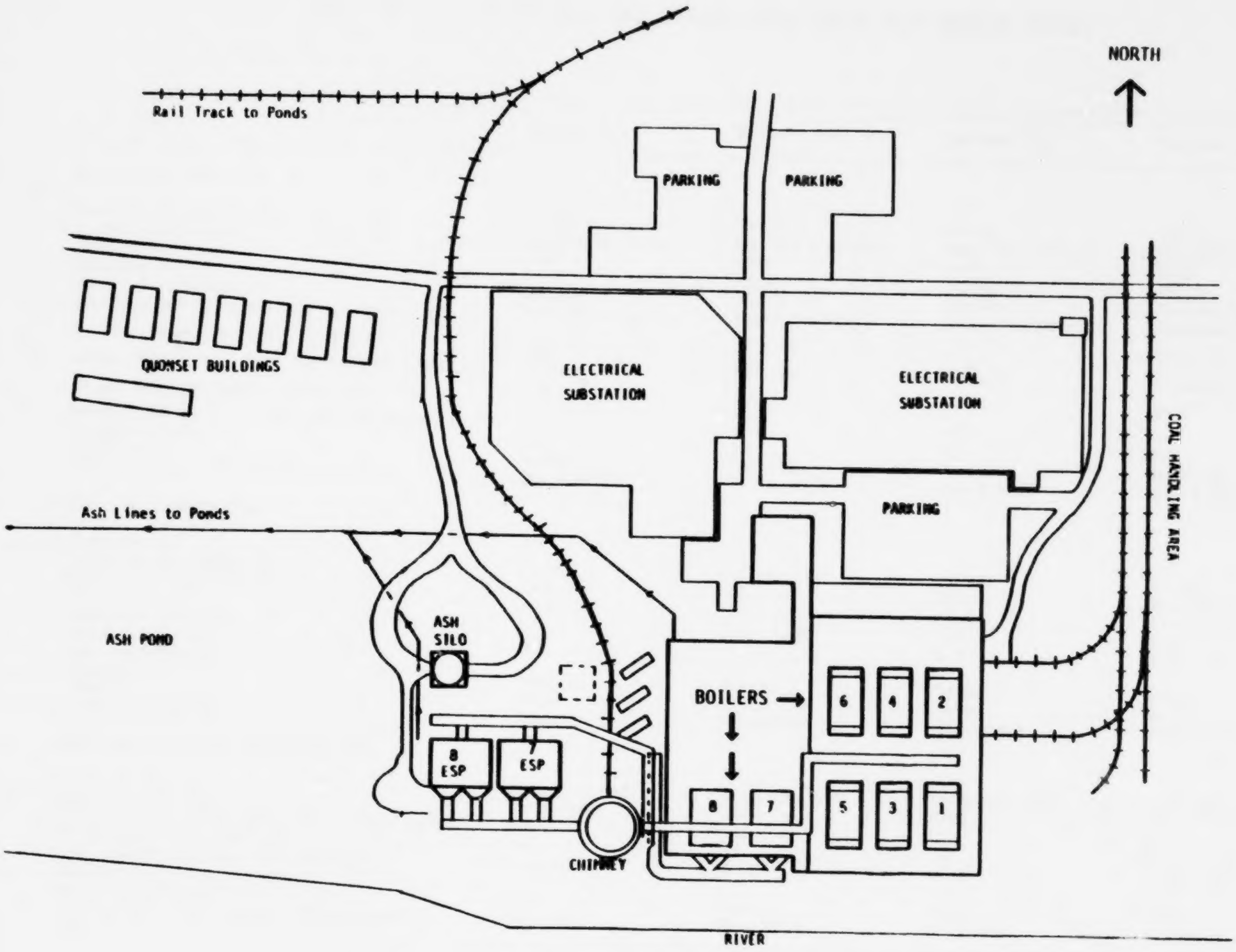

Figure 3-1. Burger plant plot plan.

TABLE 3-1. KEY DESIGN AND OPERATIONAL DATA FOR BURGER PLANT

Item	Boilers 1-2	Boilers 3-4	Boilers 5-6	Boilers 7-8
BOILER AND STACK DATA				
Generating capacity (MW)	30 ea.	30 ea.	45 ea.	150 ea.
Boiler manufacturer	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox
Installation date	1944	1947	1950	1955
Capacity factor	29/30	30/30	31/36	38/56
Heat rate (Btu/kW-hr)	15,650	15,594	12,885	11,082/10,526
Boiler type/firing type/bottom type	Roof-fired/dry	Roof-fired/dry	Roof-fired/dry	Front-wall/dry
Boiler dimensions, (ft, D x W x H[a])	20 x 30	20 x 30	--[b]	22 x 53
Burner type/number of burners (# EL x #/EL)	--[b]/1x3	--[b]/1x3	--[b]/1x8	Circular/5x4
Burner spacing (vert x horiz, ft)	--[b]	--[b]	--[b]	6x--[b]
Burner zone heat release rate (Btu/hr-ft^2)	--[b]	--[b]	--[b]	--[b]
Excess air (%)	25	25	25	25
Draft type	Balanced	Balanced	Balanced	Balanced
Flue gas flow rate (1000 acfm @ °F)	184 @ 400°F	184 @ 400°F	256 @ 345°F	600 @ 290°F
FUEL AND SORBENT DATA				
Coal quality[c]				
Heat content (Btu/lb)	12,183	12,183	12,183	12,183
Volatile matter (percent)	29.3	29.2	29.3	29.3/29.2
Ash (percent)	11.1	11.3	11.1	11.1/11.2
Moisture (percent)	5.3	5.3	5.3	5.3
Sulfur (percent)	3.7	3.7	3.7	3.7
Coal delivery methods				
Current	Barge	Barge	Barge	Barge
Design	Barge	Barge	Barge	Barge
Likely method for sorbent delivery	Truck/rail	Truck/rail	Truck/rail	Truck/rail
PARTICULATE CONTROL EQUIPMENT DATA				
Type of control	Cold-side ESP	Cold-side ESP	Cold-side ESP	Cold-side ESP
Installation date	1971/1972	1971	1971	1982
ESP specific collection area ($ft^2/10^3$ acfm)	196	196	214	409
Total plate area (10^3 ft^2)	36	36	55	261
ESP outlet emissions (lb/10^6 Btu)[d]	0.08/0.09	0.10	0.06	0.06/0.06
Design coal sulfur (percent)	1.0	1.0	1.0	2.2
Gas conditioning	None	None	None	None
Tested efficiency/design efficiency (%)	99.2/99.0	99.2/99.0	99.2/99.0	99.2/99.4

(Continued)

TABLE 3-1. (CONTINUED)

Item	Boilers 1-2	Boilers 1-2	Boilers 1-2	Boilers 1-2
NITROGEN OXIDE DATA				
NO_X control equipment	None	None	None	None
Emission rate (lb NO_x/MMBtu)	0.9	0.9	0.9	0.9
Annual emissions (tons)[e]	350 ea.	350 ea.	520 ea.	2,100/3,200
SULFUR DIOXIDE DATA				
SO_2 control equipment	None	None	None	None
Emission Rate (lb SO_2/MMBtu)	5.9	5.9	5.9	5.9
Annual emissions (tons)[e]	2,300 ea.	2,300 ea.	3,400 ea.	14,700/21,700
SOLID WASTE DISPOSAL DATA				
Ash transport system type				
Boiler bottom ash	Wet	Wet	Wet	Wet
ESP hoppers	Wet	Wet	Wet	Dry
Ash disposal method	On-site	On-site	On-site	Off-site
Estimated distance to off-site waste disposal	N/A[f]	N/A	N/A	1 mile

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

[e] Based on 1985 coal quality and unit capacity factors on 30 percent for units 1-6, 38 percent for unit 7, and 56 percent for unit 8.

[f] N/A = Not applicable.

ascending generator unit number are 60, 60, 90, 150, and 150 MW. Boilers 1-6 are cycling units at the bottom of the system dispatch order. Boilers 7 and 8 are base loaded units. Capacity factors used to analyze the cost of individual technologies were 30 percent for units 1-6, 38 percent for unit 7, and 58 percent for unit 8.

All of the boilers burn high-sulfur (3.4-3.9 percent) coals from the local area in Ohio and West Virginia. Average heating value and ash content are 12,183 Btu/lb and 11.0 percent, respectively. Current plant emissions based on this coal and the above capacity factors are 52.6 thousand tons of SO_2 and 7.6 thousand tons of NO_x.

Particulate emissions from boilers 1-6 are controlled with ESPs located on the upper section of each boiler. Treated flue gas exiting these boilers is combined and ducted to a common chimney located west of boiler 8. Untreated flue gas from boilers 7 and 8 is ducted past the chimney to retrofit ESPs located on the west side of the chimney; the cleaned gas is returned to the common chimney. Located to the north of these ESPs is the fly ash silo for boilers 7 and 8. Dry fly ash is loaded into trucks for transport to a disposal site one mile from the plant.

To the west of the boiler 7 and 8 ESPs is the bottom ash sluice pond for boilers 7 and 8 and the fly ash sluice pond for boilers 1-6. Inland from the sluice ponds is a quarry, the bottom ash piles for boilers 1-6, and seven Quonset huts. Inland from the huts is a large open field owned by Ohio Edison. North of the boiler/turbine building is the administration building, followed by the administrative parking lot, the transmission yard, and finally the employee parking area.

3.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Burger Plant include lime/limestone wet scrubbing (lime, limestone, limestone with organic acid addition, lime with MgO addition), lime spray drying, coal switching, and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates developed.

3.2.1 Lime/Limestone and Lime Spray Drying FGD

3.2.1.1 Control Cases Evaluated--

Table 3-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. Because boilers 1-6 share a common flue gas duct to the existing chimney, these units were evaluated as a single system rather than as individual boilers. Individual retrofit factors were developed for boilers 7 and 8. To demonstrate economies-of-scale from combining all process areas, a combined L/LS FGD case for boilers 1-8 was evaluated.

For the LSD FGD cases, the existing ESPs for boilers 7 and 8 were estimated to be adequate for particulate removal. As such, for these boilers, individual LSD FGD cases with reuse of the existing ESPs were evaluated. Because the boiler 1-6 ESPs are small (~200 SCA) and are located near the boiler air heater, their reuse is impractical. For these boilers, only a combined LSD FGD system with new fabric filters was evaluated.

3.2.1.2 Layout Of Equipment and Design Basis--

Figure 3-2 shows the general layout and location of the L/LS FGD control system. Due to spatial constraints around the existing chimney and boiler, the FGD system was located on the ash sluice pond adjacent to unit 7 and 8 ESPs. Once this pond is backfilled, ample space should be available for the majority of the FGD control equipment. The reagent preparation equipment was located in the Quonset building area. New breaching ducts would be required to divert the flue gas from the existing ESPs to the scrubber system. An additional draft booster fan would be installed to overcome the pressure drop of the FGD system. To minimize duct runs for all L/LS FGD cases, a new chimney was assumed to be installed near the scrubber flue gas outlet.

Figure 3-3 shows the equipment layout and location of the LSD FGD system. As with the L/LS FGD system, the spray dryer vessels are located on the backfilled ash pond, and reagent preparation is located in the Quonset building area. The ESPs on boilers 1 through 6 are not reused, because they

TABLE 3-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR BURGER PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1-6	90	3.7	14,500
Boiler 7	90	3.7	13,300
Boiler 8	90	3.7	19,500
LSD FGD			
Boiler 1-6	86	3.7	13,900
Boiler 7	64	3.7	9,400
Boiler 8	64	3.7	13,900
LOW COST CONTROLS			
L/LS FGD			
Boilers 1-8	90	3.7	47,900

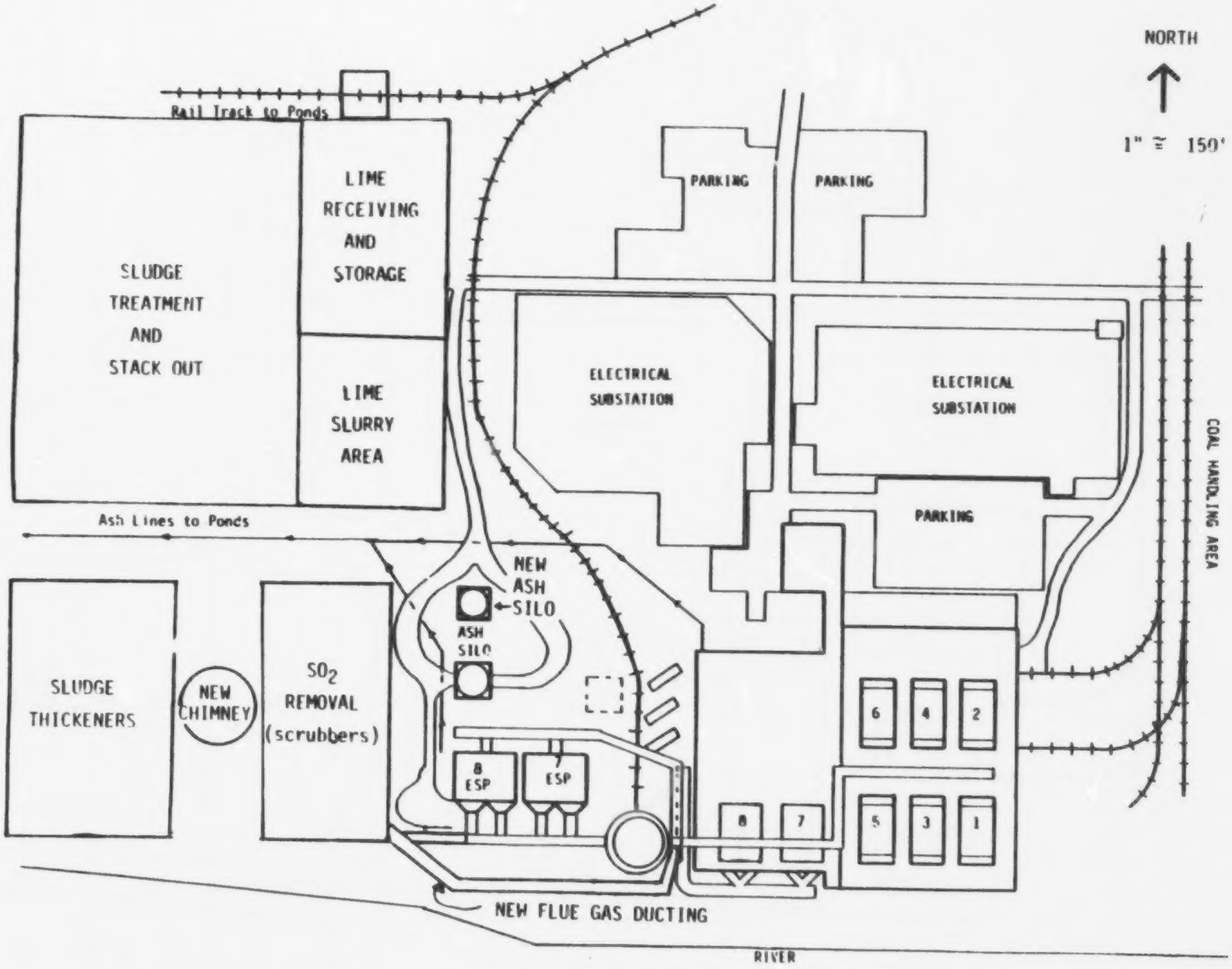

Figure 3-2. Burger Plant L/LS plot plan.

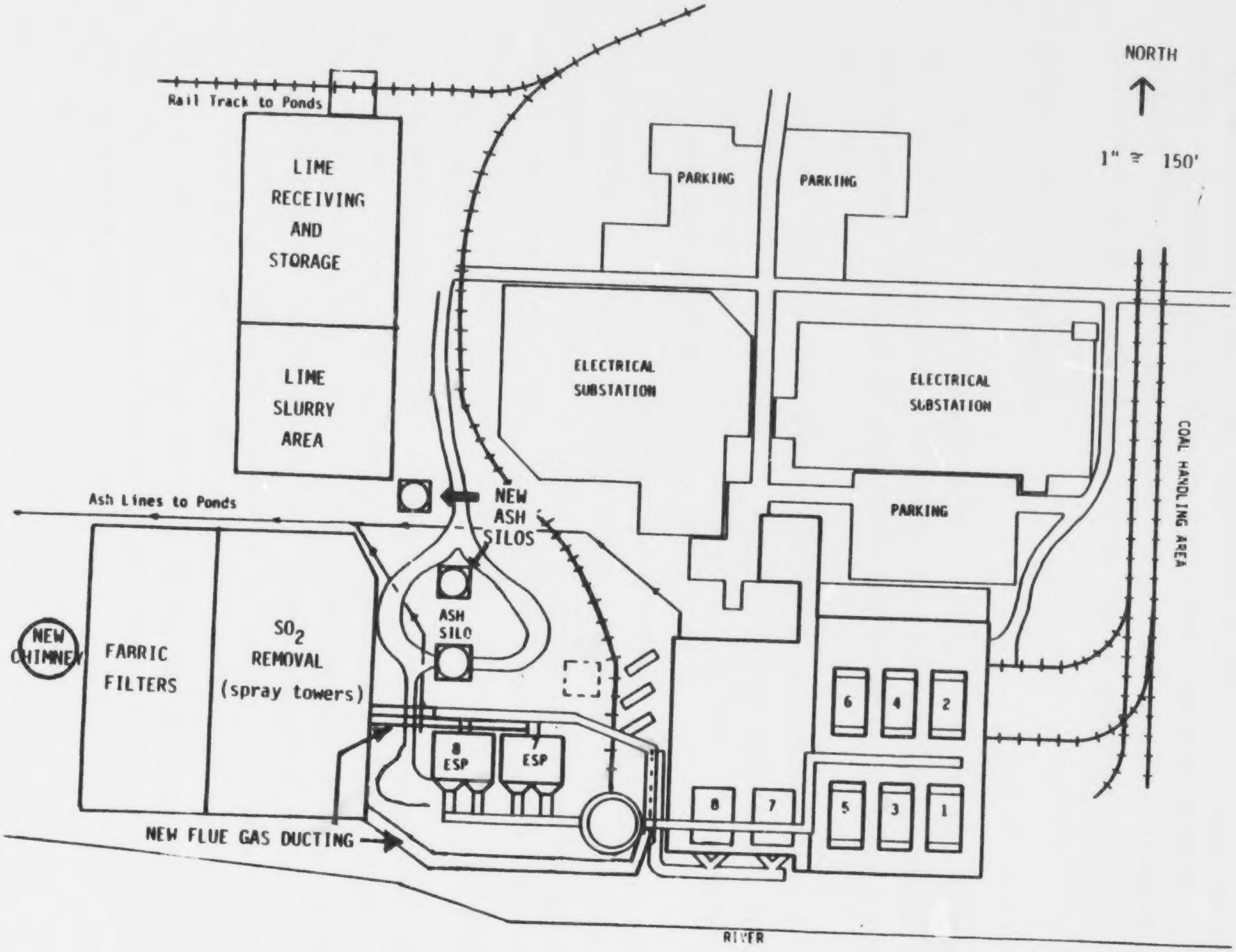

Figure 3-3. Burger Plant LSD FGD plot plan.

are remotely located from the spray dryer vessels. As a result, a new baghouse and chimney for these units would be constructed near the spray dryers. Scrubbed flue gas from boilers 7 and 8 would be treated in the existing ESPs and exhausted through the existing chimney. An additional fly ash silo would be installed to store the larger volume of ESP ash.

3.2.1.3 Scope Adjustments--

In order to retrofit a FGD control system at Burger, some of the existing site equipment must be modified and equipment not included in IAPCS must be added. These scope adjustments are summarized in table 3-3 for all FGD cases.

For all L/LS FGD cases and the LSD FGD cases with new fabric filters, returning the flue gas back to the existing chimney would result in flue gas ducting costs greater than for a new chimney. As such, it was assumed for these cases that a new chimney would be built.

To provide space for the reagent preparation equipment, seven Quonset buildings must be demolished and replaced. These buildings are frame sheds with approximately 1,000 ft^2 of area. Demolition costs were estimated using retrofit guidelines prepared by EPRI. The replacement cost of these storage sheds and the ash pond was covered by increasing the general facilities percentages to 10 percent.

Conversion of the boiler 1-6 fly ash handling systems from wet to dry disposal was assumed so that the dry fly ash could be used to stabilize the L/LS FGD scrubber sludge. Spent sorbent from the spray dryer system would be removed from the new baghouse with a pneumatic disposal system and thus fly ash conversion would not be required for boilers 1-6. However, for the boiler 7 and 8 LSD FGD cases where the existing ESPs were assumed to be reused, an additional silo was added to handle the increased solid waste load. Particulate collector costs for new fabric filters or ESP upgrading were estimated by IAPCS.

TABLE 3-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR BURGER PLANT

Scope Adjustment	Description[a]
• New chimney	A new chimney was added to all L/LS FGD cases and the LSD FGD case with new fabric filters on boilers 1-6 because reuse of the existing chimney would be more expensive ($7.00/kW).
• Modify draft controls	Additional draft controls were required for all FGD cases ($1.20/kW).
• Building demolition and replacement	Quonset building demolition costs were included for all FGD cases ($0.22 to $0.82/kW). Costs of replacement were included by increasing general facilities.
• Ash removal/conveyance modification	For the boiler 1-6 L/LS FGD case, the wet fly ash conveying system was converted to dry handling ($8.62/kW). For the boiler 7 and 8 LSD FGD cases, an additional ash silo was added ($1.35/kW).
• New ash pond	Costs for a new bottom ash pond for boilers 7 and 8 were included by increasing general facilities.

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

3.2.1.4 Location and Retrofit Factors--

Tables 3-4 thru 3-6 present the location and retrofit factors used for L/LS and LSD FGD. The aggregate location factor presented in the column titled LOCF incorporates the following factors: seismic zone factor of 1.0, climate zone factor of 1.0, and labor productivity and materials factor of 1.06. The soil factors vary by process area and FGD type and assume ground

TABLE 3-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR BURGER PLANT

		RETROFIT FACTORS											
	All Units	Boiler #1-6				Boiler #7				Boiler #8			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT													
Reagent Feed	1.09	1.01	1.02	1.03	1.06	1.01	1.02	1.01	1.04	1.01	1.02	1.01	1.04
SO_2 Removal	1.08	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
Flue Gas Handling	1.09	1.00	1.02	1.40	1.43	1.00	1.02	1.45	1.48	1.00	1.02	1.55	1.58
Waste Handling	1.08	1.00	1.02	1.03	1.04	1.00	1.02	1.02	1.04	1.00	1.02	1.01	1.03
General Support Equipment	1.09	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
SCOPE ADJUSTMENTS													
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00	N/A[f]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Chimney	1.11	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES													
Engineering - %			10					10				10	
General Facilities - %			10					10				10	

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 3-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

[f] N/A = Not applicable.

TABLE 3-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR BURGER PLANT

		RETROFIT FACTORS											
	All Units	Boiler #1-6				Boiler #7				Boiler #8			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT													
Reagent Feed	1.17	1.01	1.02	1.00	1.03	1.01	1.02	1.01	1.04	1.01	1.02	1.01	1.04
SO_2 Removal	1.16	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
Flue Gas Handling	1.16	1.00	1.02	1.30	1.33	1.00	1.02	1.45	1.48[f]	1.00	1.02	1.45	1.48[f]
General Support Equipment	1.16	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
SCOPE ADJUSTMENTS													
New Ash Silo System	N/A[g]	N/A	N/A	N/A	N/A	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.00
Chimney	1.11	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
Baghouse	1.16	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
ESP Plate Addition	N/A	N/A	N/A	N/A	N/A	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES													
Engineering - %			10					10				10	
General Facilities - %			10					10				10	

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 3-7 for distance assumptions used.
[e] AGGF = Aggregate Factor.
[f] Based on reusing ESP. If a new baghouse is used, the aggregate factor is 1.17.
[g] N/A = Not applicable.

TABLE 3-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES EVALUATED FOR BURGER PLANT

	RETROFIT FACTORS				
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.09	1.01	1.02	1.03	1.06
SO_2 Removal	1.08	1.00	1.02	1.00	1.02
Flue Gas Handling	1.09	1.00	1.02	1.70	1.73
Waste Handling	1.08	1.00	1.02	1.01	1.03
General Support Equipment	1.09	1.00	1.02	1.00	1.02

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 3-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

water at 3 feet for the reagent feed, waste handling, and general support equipment process areas. Because the SO_2 removal and flue gas handling areas and chimney are near the river and on an old ash pond, flood plain soil factors were used.

For the low cost L/LS FGD case in which boilers 1-8 are combined, the location and retrofit factors are the same. Table 3-6 summarizes retrofit factors for the combined case. The flue gas ducting distances and distances between process areas were adjusted as presented in table 3-7.

Since the SO_2 removal process area and new chimney would be located on the backfilled sluice pond, without significant underground obstructions, no adjustments were made. For reagent preparation and ash disposal, minor underground obstructions exist and were assessed a retrofit factor of 1.01. With relatively free access and very little congestion around the proposed FGD equipment location, a base case factor of 1.02 was used for all process areas. Table 3-7 presents the duct tie-in distances and distances between process areas.

3.2.1.5 Overall Retrofit Factors and Costs--

Table 3-8 presents the overall retrofit factors and costs for all FGD cases. The range of costs shown for L/LS FGD reflect the different process options evaluated: conventional and adipic acid enhanced limestone FGD and conventional and MgO enhanced lime FGD. The LSD FGD costs include 1) upgrading the ESPs and ash handling systems for boilers 7 and 8 and 2) installing new baghouses to handle the additional particulate loading for boilers 1-6.

Figures 3-4 and 3-5 summarize the plant level costs of installing L/LS and LSD FGD. The costs presented are for the lime FGD case which are slightly lower than those presented in table 3-8. The data point labeled low cost shows the impact of economies-of-scale when combining process areas, elimination of a spare scrubber, optimization of scrubber size, and use of organic acid additives.

For Burger, the low cost control case reduces capital and annual operating costs by 40 to 50 percent. The significant reduction in costs is

TABLE 3-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR BURGER PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
L/LS FGD				
Boilers 1-6	400	150	450	450
Boiler 7	450	150	300	350
Boiler 8	550	150	250	300
Boilers 1-8	500	350	450	300
LSD FGD (new baghouse)				
Boilers 1-6	400	50	150	N/A[c]
LSD FGD (reuse ESP)				
Boiler 7	300	300	300	N/A
Boiler 8	300	300	250	N/A

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

TABLE 3-8. L/LS AND LSD FGD COSTS FOR BURGER PLANT (August 1987 Dollars)

Case Description	Overall Retrofit Factor	IAPCS Retrofit Costs[a] Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boilers 1-6	1.30	239.8-276.9	1,218-1,368	32.2-36.1
Boiler 7	1.26	265.3-307.1	1,112-1,252	29.4-33.1
Boiler 8	1.29	269.0-311.5	845-954	22.3-25.2
LSD FGD (new baghouse)				
Boiler 1-6	1.50[b]	325.2	1,463	37.1
LSD FGD (reuse ESP)				
Boiler 7	1.19[c]	159.4	954	17.9
Boiler 8	1.19[c]	160.6	704	13.2
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1-8[d]	1.38	142.9	574	15.1

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] Includes impact of new baghouse.

[c] Does not include plate area increase if needed.

[d] Based on lime slurry with MgO addition.

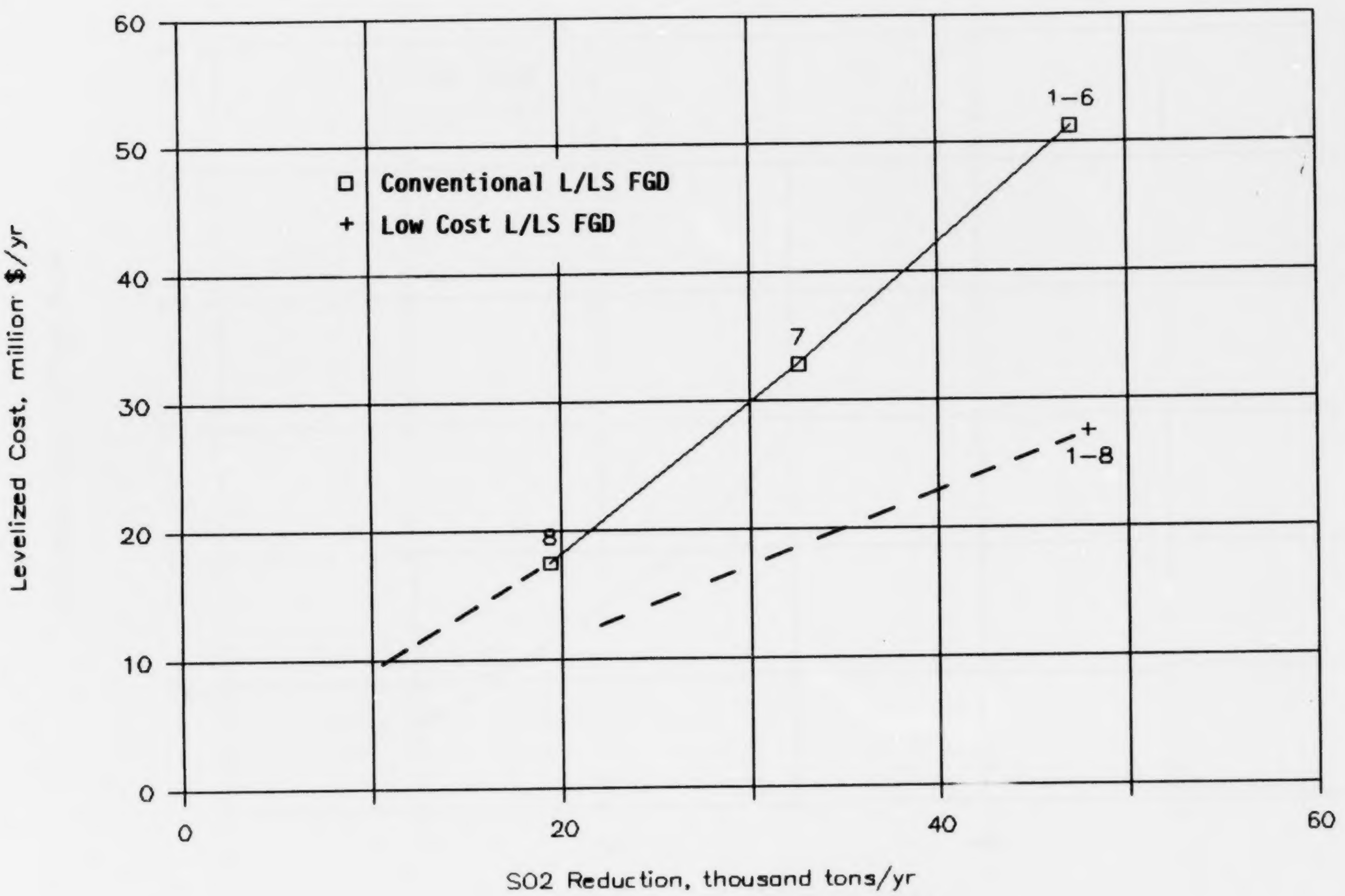

Figure 3-4. Burger Plant L/LS cost versus SO_2 reduction.

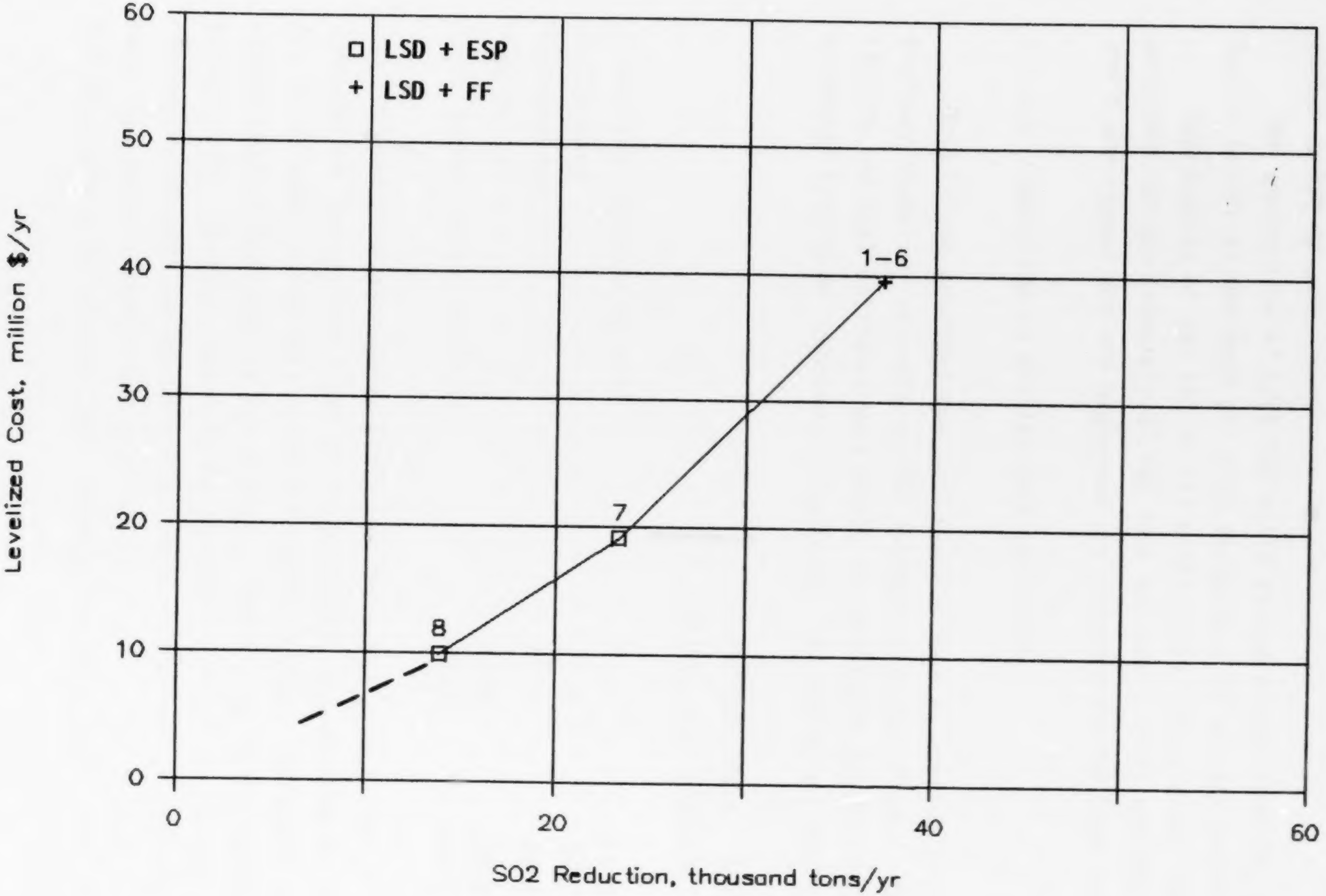

Figure 3-5. Burger Plant lime spray dryer FGD cost versus SO_2 reduction.

primarily due to the benefits of economies-of-scale; 160 to 225 MW units versus a 550 MW unit.

The application of L/LS FGD would reduce plant level SO_2 emissions by approximately 47,000 tons per year assuming a 90 percent level of control.

Application of LSD FGD at all units would reduce plant level SO_2 emissions by approximately 37,000 tons per year. This assumes that boiler 7 and 8 are reused and new baghouses are required for boilers 1-6.

3.2.1.6 Comparison to Utility Cost Estimates--

Ohio Edison provided the cost results from an earlier architect/engineer study for retrofit of FGD systems at Burger Plant. The FGD system layouts and cost estimates were based on conceptual engineering and budget estimates from major component suppliers. The estimated capital costs were:

	Capital Costs - $/kW	
	Boilers 1-6	Boilers 7 & 8
Direct Cost Materials/Labor	279.1	240.8
Contingency	55.9	48.2
Engineering	38.5	33.2
Home Office	19.5	16.8
Total Direct Cost - (1987 $)	393.0	339.0

The EPRI detailed procedures estimated the total direct capital cost at $349-356/kW for boilers 7 and 8, respectively, and $342/kW for boilers 1-6. The IAPCS model using EPRI-derived retrofit factors estimated the total direct cost at $265-311/kW for boilers 7 and 8, and $235-271/kW for boilers 1-6. However, the Ohio Edison costs include an inconel-lined new chimney which adds $67-89/kW to the total direct cost. The EPRI and IAPCS model estimates assume a new acid resistant brick chimney which adds only $12/kW to the total direct cost. Adding the incremental cost of an inconel liner for the new chimney would increase the EPRI and IAPCS cost estimates as follows:

	EPRI Estimate		IAPCS Estimate	
Boiler Number	Brick	Inconel Lined	Brick	Inconel Lined
Combined 1-6	342	409	277	344
Individual 7 and 8	349 and 356	438 and 445	307 and 311	396 and 400

These costs compare favorably with those provided by the utility and point out the impact that scope assumptions can have in comparing cost estimates. Additionally, these costs do not include the impact of interest during construction. Methods used to estimate interest during construction vary, and these differences can have a significant impact on cost estimates.

3.2.2 Coal Switching/Blending

Presented in table 3-9 are the coal analyses for the coal used at Burger in 1985 and the alternative coal used to evaluate coal switching. The primary coal used in 1985 was a washed Ohio coal; no ash analysis was provided by the plant.

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. For boilers 1-6 with SO_3 conditioning, a 28-37 percent increase in the existing ESPs would be needed for low-sulfur coal service. However, because the benefits of SO_3 conditioning are highly variable, the predicted cost for ESP plate area increase should be viewed as a minimum estimate. For boilers 7 and 8 no additional plate area would be required.

TABLE 3-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR BURGER PLANT

	Existing Coal			Switch Coal			Cleaned Coal		
	Boilers			Boilers			Boilers		
Item	1-4	5-6	7-8	1-4	5-6	7-8	1-4	5-6	7-8
COAL PARAMETERS									
Percent Sulfur		3.7			0.9			2.7	
Percent Ash		11.0			8.8			5.6	
Btu Per Pound		12,083			12,554			12,966	
ESP PARAMETERS									
Existing/Needed SCA[a]	196	214	409	269	273	213	268	263	213

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

The current coal receiving/storage/handling facilities at Burger should be adequate to handle low-sulfur eastern coals received by barge. However, if a segregated pile system was needed to accommodate low-sulfur coal at some units or blending, additional equipment would be needed. This could include another bunker and conveyor system for the new pile along with an additional breakhouse and crusher system. This cost was not included in the annual cost of coal switching, but it would probably have a very small impact (< $3/ton). Capital costs were included for the ESP upgrades and coal inventory.

Figure 3-6 presents the plant level cost and emission reduction for switching to a low-sulfur coal. Approximately 40,000 tons per year of SO_2 reduction would be achieved by switching Burger to a coal having a 1.4 pound per million Btu SO_2 emission rate. Curves were generated to show the impact of different coal fuel cost differentials. The baseline curve represents a 1985 fuel cost differential of $14.55 per ton between the existing coal ($32.07/ton) and an eastern Kentucky low-sulfur coal ($46.62/ton). The upper curve shows the impact of an additional fuel cost differential of $15 per ton over the 1985 fuel cost differential of $14.55. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 3-10.

TABLE 3-10. COAL SWITCHING COSTS FOR BURGER PLANT
(August 1987 Dollars)

		@ $14.55/ton FCD		@ $29.55/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1-6	12,900	571	12.9	1,044	23.4
7	11,300	480	10.8	945	21.2
8	16,600	459	10.3	913	20.5
1-8	40,800	500	11.5	964	21.6

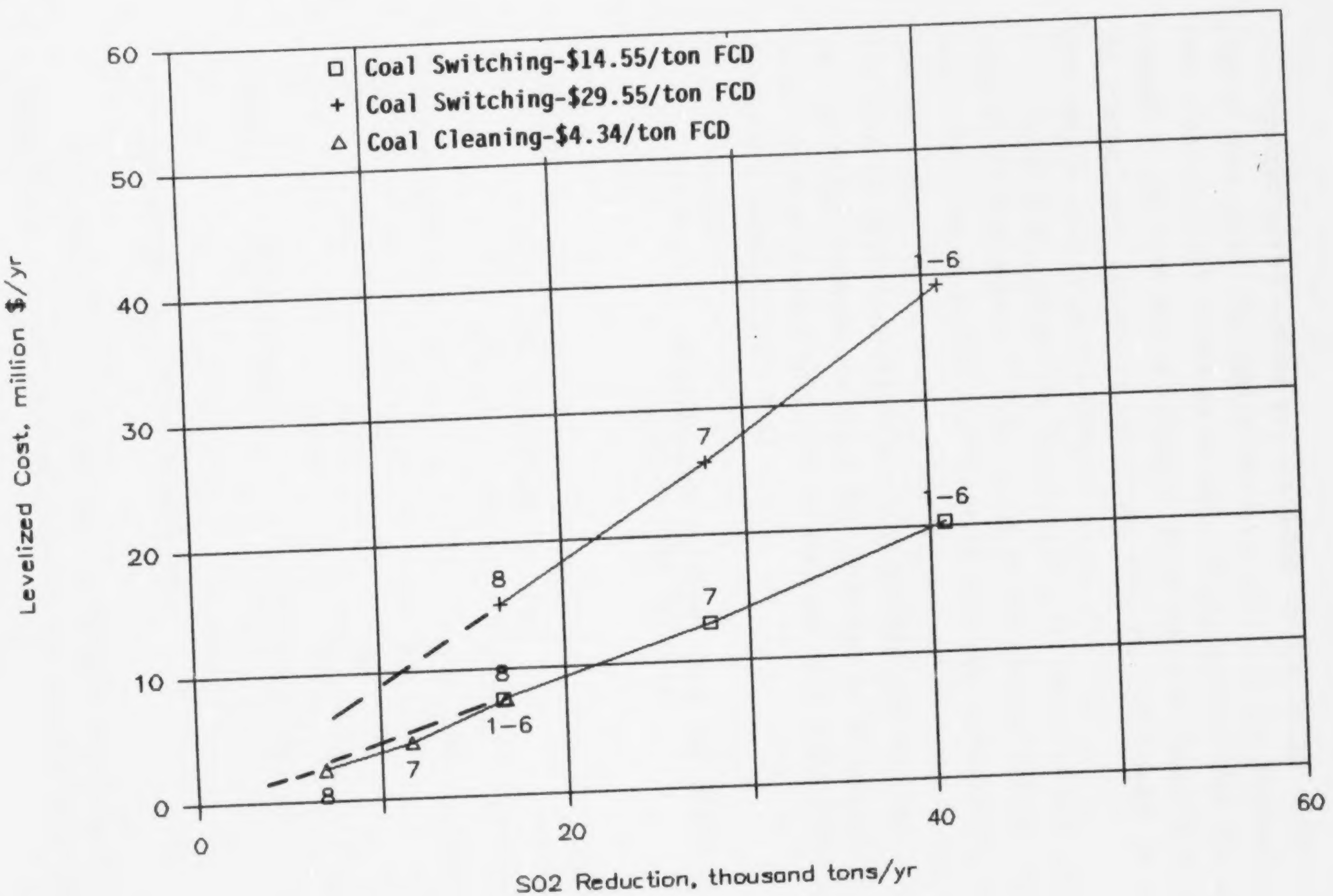

Figure 3-6. Burger Plant coal switching/cleaning costs versus SO_2 reduction.

3.2.3 Physical Coal Cleaning

Physical coal cleaning was evaluated for the Burger Plant using a similar Ohio coal. The cost of cleaning this coal was estimated using a coal cleaning model developed by TVA. It was assumed that the coal would be cleaned at the mine and no refuse disposal would be required at the plant. The cleaned coal parameters were input into the IAPCS model to estimate performance impacts on the ESPs.

Figure 3-6 presents the IAPCS results for physical coal cleaning at the eight boilers at Burger. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal. The costs do include the estimated increase in coal cost for the cleaning operation ($4.34 per ton) and ESP upgrade costs. Cleaning the coal at Burger reduces the plant SO_2 emissions by 32 percent (17,000 tons/yr) at an average unit cost of $442 per ton. Cost estimates for each boiler are shown in table 3-11.

TABLE 3-11. PHYSICAL COAL CLEANING COSTS FOR BURGER PLANT
(August 1987 Dollars)

Boiler	SO_2 Reductions (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1-6	5,200	600	5.7
7	4,700	397	3.7
8	6,900	363	3.4

3.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from commercial technologies because their cost/performance estimates have a high degree of uncertainty due to the lack of commercial data. For the Burger Plant, the following control technologies were evaluated: furnace sorbent injection (FSI) on boilers 7 and 8, duct spray drying (DSD) on boilers 1-8, and repowering emission control technologies (e.g., AFBC) on boilers 1-8.

3.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. As such, many retrofit costs are built into the base case design and costs. The retrofit factors developed for these technologies focus on scope adders that are not included in developers' assumptions. These scope adders include ESP/fabric filter additions, demolition/relocation of existing equipment/buildings, and conversion of wet fly ash handling systems to dry handling/storage. Basic assumptions and cost adjustments made for FSI and DSD are presented in table 3-12.

3.3.1.1 Furnace Sorbent Injection--

FSI retrofit factors were developed for boilers 7 and 8. Boilers 1-6 are top-fired boilers and are not considered candidates for this technology. The sorbent was assumed to be a prepared calcitic hydrate material with the receiving/storage facilities located north of the existing boiler 7 and 8 bottom ash pond and west of the existing electrical substation yard. This location was chosen because of its access to existing roads and railroad spur. Approximately 1,200 feet of sorbent conveying line would be required to reach the injection day tanks located south of the boiler 7 and 8 buildings. The additional solid waste storage silo was located just north of the existing silo. It was assumed that the alkaline waste material could be disposed of at the existing off-site landfill.

The ESPs for boilers 7 and 8 were recently installed and have SCAs of >400. IAPCS estimated that with flue gas humidification no additional ESP

TABLE 3-12 SCOPE ADJUSTMENTS FOR FSI AND DSD AT BURGER PLANT

Item	Boiler 1-6	Boiler 7	Boiler 8
BASIC ASSUMPTIONS			
Approximate access/congestion rank	Low	Low	Low
Can the existing ESP be upgraded?	No	Yes	Yes
Was a new baghouse evaluated for DSD?	Yes	No	No
Distance to final waste disposal (miles)	1	1	1
SCOPE ADDERS			
Install dry ash handling system[a]	N/A[b]	No	No
New stack	Yes	No	No
Additional duct work (ft)[c]	400	0	0
Duct demolition length (ft)	50	0	0
Building demolition area (ft^2)	0	0	0
ADDER COSTS AND RETROFIT FACTOR SUMMARY			
Scope adder cost for new baghouse (10^3 \$)[d]	5404	N/A	N/A
Scope adder costs for ESP reuse (10^3 \$)[d]	N/A	18	42
Baghouse retrofit difficulty factor	1.02	N/A	N/A
ESP upgrade retrofit difficulty factor (for plate area addition)	N/A	1.02	1.02

[a] Not applicable when a new baghouse is installed.

[b] N/A = Not applicable.

[c] Not applicable when the existing ESP is used.

[d] June 1985 dollars.

plate area will be needed for adequate particulate control. For all process areas, underground obstructions should not be a problem and site access and congestion factors for the sorbent receiving/storage and waste handling would be the same as the base case.

3.3.1.2 Duct Spray Drying--

The calcium-based sorbent receiving/storage/conveying systems for the duct injection technologies would be the same as for FSI. Facilities for slurry preparation would be located adjacent to the dry sorbent handling facilities.

The existing particulate control systems for boilers 7 and 8 should be satisfactory for particulate removal. However, boilers 1-6 would require new fabric filters to be located west of unit 7 and 8's ESPs. Retrofit factors for access/congestion, underground obstructions, soil conditions, and location would be minimal. The overall retrofit difficulty of adding fabric filters was estimated to be 1.02 (low access/congestion difficulty).

Major process parameters associated with the performance of duct injection are duct residence time and flue gas temperatures. Duct residence times for all of the Burger boilers should be quite sufficient due to the long duct runs between the boilers and the new particulate control equipment. On boilers 1-6 the air heater flue gas outlet temperature is high (370^{0}F) and sufficient heat should be available to completely dry the lime slurry droplets before entering the particulate control system. A SO_2 removal efficiency of 68 percent was estimated for boilers 1-6 if fabric filters are used for particulate control. The air heater outlet flue gas temperature for boilers 7 and 8 of near 300^{0}F and a 42 percent SO_2 reduction was estimated when the ESPs are reused.

3.3.1.3 Overall Retrofit Factors and Costs--

Table 3-13 presents the estimated retrofit costs for FSI and DSD. Figure 3-7 presents the cost of retrofitting FSI on boilers 7 and 8 and DSD on boilers 1-8 versus the plant level SO_2 reductions achieved.

TABLE 3-13 RETROFIT COSTS FOR FSI AND DSD FOR BURGER PLANT
(August 1987 Dollars)

Case Description	IAPCS Capital Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50 % removal)[a]				
Boiler 7	58.0	12.3	838	7,400
Boiler 8	58.2	10.6	721	10,800
Furnace Injection (70 % removal)[b]				
Boiler 7	58.2	12.4	602	10,300
Boiler 8	58.4	10.6	519	15,200
Duct Spray Drying				
Boilers 1-6 (new baghouse)	203.1	25.4	1,284	10,900
Boiler 7 (ESP reuse)	56.7	10.5	853	6,200
Boiler 8 (ESP reuse)	56.9	8.1	657	9,100

[a] The case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

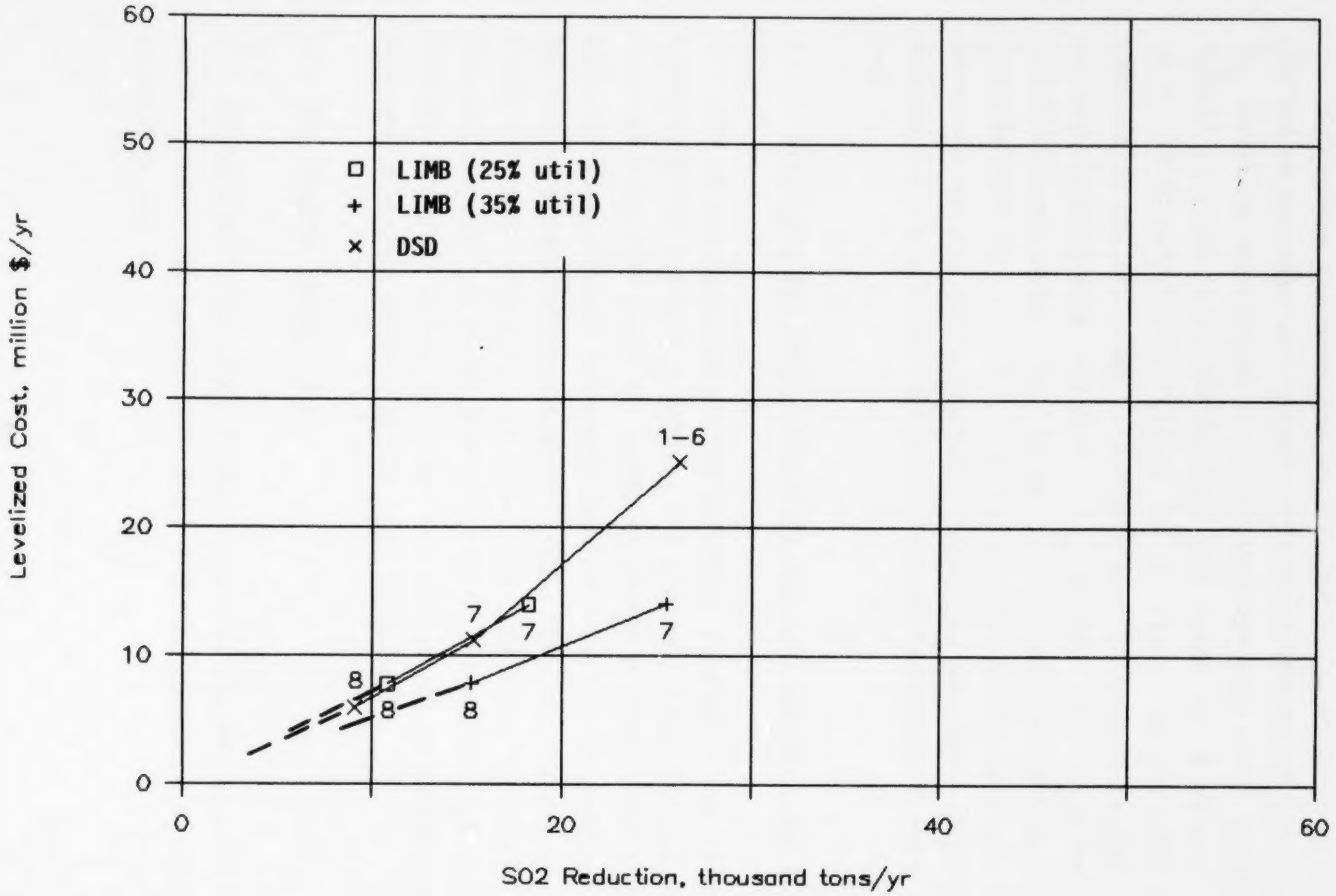

Figure 3-7. Burger Plant FSI/DSD cost versus SO_2 reduction.

Two curves are presented to span the range of anticipated SO_2 removal (50 and 70 percent) and sorbent utilization (25 and 35 percent) for FSI. SO_2 emissions are reduced by 18,200 tons per year under the 50 percent SO_2 removal case and by 25,500 tons per year under the 70 percent SO_2 removal case. If 50 percent SO_2 removal and 25 percent sorbent utilization is achieved at boilers 7 and 8, the unit cost of control is $837 and $721 dollars, respectively, per ton of SO_2 removal. If 70 percent SO_2 removal and 35 percent sorbent utilization is achieved, the unit cost of control for these boilers would be $602 and $519 per ton of SO_2 removed. Plant-wide SO_2 emissions for DSD are reduced by 26,200 tons per year. Cost estimates for boilers 1-6 include new fabric filters, while boilers 7 and 8 assume ESP reuse.

3.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

All of the Burger units are potential candidates for life extension through FBC/CG retrofit. Boilers 1-6 are candidates because of their small size and high heat rates of 12,885 to 15,650 Btu/kWh. Additionally, the ESPs for these boilers are small and would have to be replaced if the boilers were switched to low-sulfur coal. Boilers 7 and 8 are also relatively small and old, and, thus, are candidates for FBC/CG retrofit. However, because these two have lower heat rates of 10,500 to 11,100 Btu/kWh, are base loaded, and have the ESPs sized to handle low-sulfur coal, they are also good candidates for coal switching.

3.4 NO_x CONTROL TECHNOLOGIES

NO_x controls evaluated at Burger include low NO_x burners on boilers 7 and 8, natural gas reburn on boilers 1-6, and selective catalytic reduction on boilers 1-8.

3.4.1 Low NO_x Burners

Low NO_x burners (LNB) are not available for roof-fired furnaces such as boilers 1-6. As a result, LNB retrofit would be very difficult, even with custom designed modifications. Boilers 7 and 8, equipped with circular burners in a front wall-fired furnace design, are amenable to a LNB retrofit. The burner heat input (74 million Btu/hr) relative to the furnace depth (22 feet) and to the furnace height above the top burner row (24 feet) is moderate. As a result, flame impingement on the rear furnace wall and/or superheater tube surfaces could limit the NO_x reduction performance of a LNB retrofit. However, the burner heat input relative to the vertical burner spacing (6 feet) is low for circular burners. Flame interaction between burner rows should be minimal, not significantly impacting LNB performance.

Plant personnel indicated there were no slagging problems on boilers 7 and 8. This may be due in part to the relatively high excess air levels (approximately 25 percent) at which these boilers operate. The existing high-sulfur coal (3.5 percent) could present some corrosion problems if increased slagging occurs due to the reducing atmospheres and increased furnace exit gas temperatures associated with LNB. This could result in lower NO_x reductions, boiler derating, or switching/blending with coals of higher ash fusion temperatures. Based on the current lack of slagging problems, relatively wide burner spacing, and moderate furnace depth and height, LNB retrofit on boilers 7 and 8 should exhibit intermediate to high NO_x reduction performance.

3.4.2 Natural Gas Reburning

Natural gas reburning (NGR) was assumed to be applicable for boilers 1-6. A NO_x emission reduction of 50 percent was estimated to be achievable with injection of 15 percent of the boiler heat input as natural gas in the secondary furnace area.

3.4.3 Selective Catalytic Reduction

A tail-end SCR system with flue gas preheat was selected for boilers 1-8. This system was selected because all boilers are enclosed in the boiler building which severely limits access around the air heater areas. The SCR reactors for all the boilers were located on the ash pond just west of boiler 8's retrofit ESP. Table 3-14 summarizes the key information used to develop the SCR unit retrofit difficulty and scope adjustments. The new flue gas duct lengths are for ducting the flue gases from the chimney (boilers 1-6) or ESP outlet (boilers 7 and 8) to the catalytic reactor and back to the chimney. The heat exchanger costs are for the catalytic reactor preheater to raise the flue gas temperature up to 650-700°F and to recover this heat from the flue gas leaving the reactors. The general facility costs account for new roads and soil conditions.

3.4.4 Summary of NO_x Control Costs

Table 3-15 and figure 3-8 present the annual cost of NO_x controls. LNB and NGR assume a 50 percent NO_x reduction while SCR assumes an 80 percent reduction. The unit cost of LNB at boiler 7 and 8 was estimated to be \$478 and \$325 per ton of NO_x removed, respectively. The unit cost of NGR at boilers 1-6 was estimated to be \$2,536 to \$2,797 per ton of NO_x removed. The unit costs of NGR on tons of SO_x and NO_x removed ranges from \$828 to \$914 per ton. Application of LNB and NGR to all the boilers reduces NO_x by 3,900 tons per year. Application of SCR would reduce NO_x emissions by 6,100 tons per year if 80 percent reduction can be achieved; the cost per ton of NO_x removed is \$8,100.

TABLE 3-14 SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR BURGER PLANT

(August 1987 Dollars)

Item	Boiler 1-6	Boiler 7	Boiler 8
Site access and congestion for SCR reactor	Low	Low	Low
SCOPE ADDER PARAMETERS			
Building demolition (1,000$)	0	0	0
Ductwork demolition (1,000$)	50	38	38
New duct length (Feet)	800	500	500
New duct costs (1,000$)	6,354	3,262	3,262
New heat exchanger (1,000$)	3,024	2,471	2,471
Total scope adder costs (1,000$)	9,427	5,771	5,771
Retrofit factor for SCR	1.16	1.16	1.16
General facilities (percent)	25	25	25

TABLE 3-15. NO_X CONTROLS COSTS FOR BURGER PLANT
(August 1987 Dollars)

NO_X Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X Reduced (tons/year)
Low NO_x Burner	7	50	16.9	478	1.0	1,070
	8	50	16.9	325	0.7	1,570
Natural Gas Reburn	1	50	26.6	2,797	6.0	160
	2	50	26.6	2,797	6.0	160
	3	50	26.6	2,765	5.9	170
	4	50	26.6	2,765	5.9	170
	5	50	23.6	2,631	5.6	260
	6	50	23.6	2,536	5.4	300
Selective Catalytic Reduction	1-6	80	163.7	10,940	38.6	1,900
	7	80	166.6	7,272	24.8	1,700
	8	80	166.6	5,004	17.1	2,500

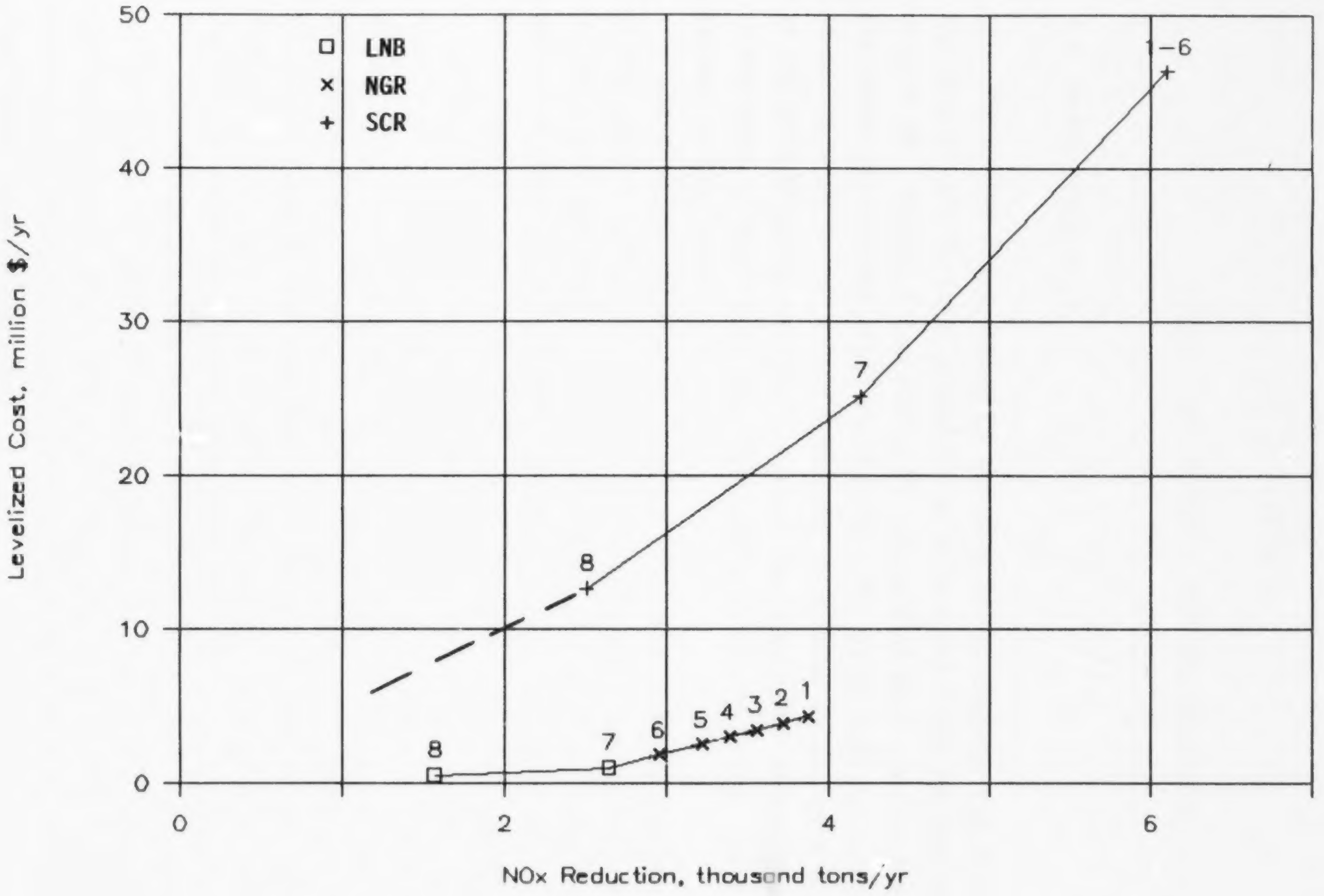

Figure 3-8. Burger Plant NO_x control cost versus NO_x reduction.

SECTION 4

SAMMIS PLANT RETROFIT FACTORS AND COSTS

4.1 PLANT DESCRIPTION

The Sammis Plant, owned by the Ohio Edison Company and located along the Ohio River, is totally coal-fired with a total net generating capacity of 2,00 MW. Figure 4-1 presents the plant plot plan showing the location of the seven boilers and other facilities. The plant site is narrow and congested with little unused space and is bounded by the main barge channel of the Ohio River to the east, a major railroad right-of-way and steep hills to the west, a small town and light industry to the south, and a major highway to the north.

The plant receives coal by truck and barge. Approximately 30 percent of the coal is delivered by truck from local mines and is received west of the main coal storage area. The remainder of the coal is received by barge and is unloaded by rotary and clamshell unloaders located on the river at the north end of the plant site. Coal from the barge unloading facilities is conveyed under the main highway to the coal storage pile. The coal stacker is located at the south end of the coal pile. Two separate piles are maintained to segregate the low-sulfur coal fired in boilers 1-4 from the moderate-sulfur coals fired in boilers 5-7. The inactive coal pile area is located north of the active piles. The total coal storage capacity is about 40 days. Coal is conveyed by two parallel systems from the breakhouses south of each active coal pile to boilers 1-4 and 5-7.

West of the breakhouses are the bottom ash and fly ash storage silos for boilers 1-4. South of the breakhouses are the plant water tower, a small parking lot, the administration building, and boiler/turbine unit 1. Southeast of the breakhouses are the maintenance/repair buildings and the plant water screen/pump house.

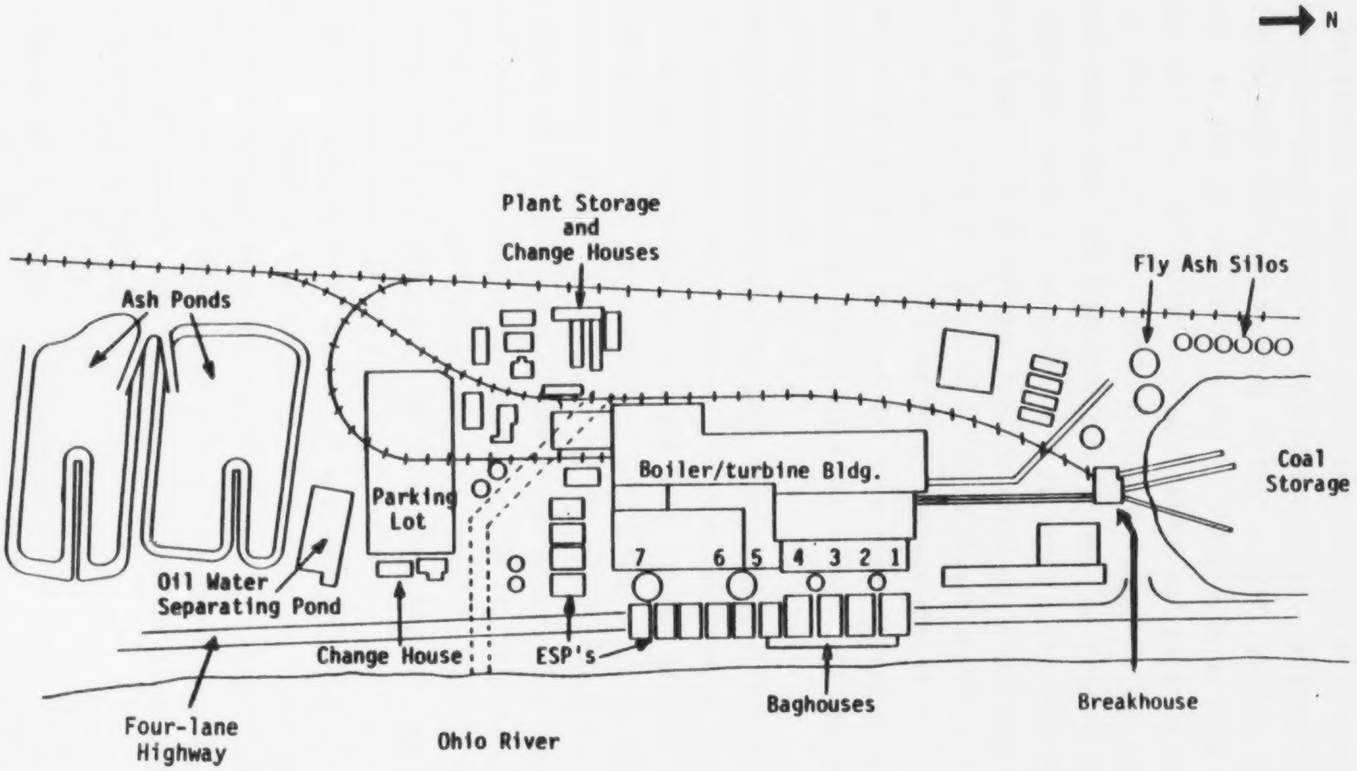

Figure 4-1. Sammis Plant plot plan.

The turbine rooms of all units are arranged in a single line with unit 1 the northernmost and unit 7 the southernmost. Boiler/turbine units 1-4 are 180 MW each and came on line in 1959 - 1962; unit 5, which came on line in 1967, is 300 MW; and units 6 and 7, which came on line in 1969 and 1970, are 600 MW each. All units are base loaded and have capacity factors greater than 50 percent. Table 4-1 presents key design and operating data for the plant obtained from EIA Form 767 and the site visit.

Boilers 1-4 burn low-sulfur (<1 percent) coals from West Virginia and Kentucky that have an average heating value of 12,085 Btu per pound and ash content of 10 percent. Boilers 5-7 burn moderate-sulfur (2.4 percent) Pennsylvania and Ohio coals having an average HHV of 12,053 Btu/lb and ash content of 12 percent. Boilers 5-7 have moderate slagging problems. Annual plant emissions based on these coals and recent capacity factors are 144,000 tons of SO_2 and 41,000 tons of NO_x.

Boilers 1-4 were retrofit with fabric filters in the early 1980's. Due to site constraints the filter houses were built above the four-lane highway which runs between the plant and the Ohio River. Boilers 5-7 were retrofit with new ESPs in the early 1980's. Unit 5 and 6 precipitators were installed also above the highway, and the precipitator for unit 7 was constructed at the south end of the boiler house. The four plant stacks are located between the boiler buildings and the particulate control buildings. Due to the previous particulate control retrofit, extensive flue gas duct runs exist from the boilers to the ESPs, from the ESPs to the new induced draft fans, and from the fans to the stacks.

The fly ash silos for units 5-7 are located south of the precipitators for unit 7. South of the ash silos is an employee parking lot, the plant oily water treatment pond, and boiler bottom ash ponds. The power transmission yard is adjacent to the turbine house extending westward to the railroad right-of-way. West of units 5-7 fly ash silos are numerous storage and changehouse buildings.

4.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

The following commercial SO_2 control technologies were evaluated at the Sammis Plant: lime/limestone wet scrubbing (lime with and without MgO

TABLE 4-1. KEY DESIGN AND OPERATIONAL DATA FOR SAMMIS PLANT

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5	Boiler 6	Boiler 7
BOILER AND STACK DATA							
Net generating capacity (MW)	180	180	180	180	300	600	600
Boiler manufacturer							
Installation date	1959	1960	1961	1962	1967	1969	1971
Capacity factor (10 year projected)	46.6	51.1	54.9	62.0	54.9	50.7	43.8
Heat Rate (Btu/kW-hr)	9,920	10,180	9,920	10,380	10,750	9,990	10,460
Boiler type/firing type/bottom type	Front wall/dry	Front wall/dry	Front wall/dry	Front wall/dry	Opposed wall/dry	Opposed wall/dry	Opposed wall/dry
Boiler dimensions, (ft, D x W x H[a])	24x49x57	24x49x57	24x49x57	24x49x57	34x61x72	39x69x94	39x69x94
Burner type/number of burners (# EL x #/EL)	Circular 5x3	Circular 5x3	Circular 5x3	Circular 5x3	Cell 6x8	Cell 4x12	Cell 4x12
Burner spacing (vert x horiz, ft)	7.25x--[b]	7.25x--[b]	7.25x--[b]	7.25x--[b]	5x--[b]	5.3x--[b]	5.3x--[b]
Burner zone heat release rate (Btu/hr-ft^2)	277,000	277,000	277,000	277,000	361,000	780,000	780,000
Excess air (percent)	30	30	30	30	30	30	30
Draft type	Balanced	Balanced	Balanced	Balanced	Balanced	Balanced	Balanced
Flue gas flow rate (1000 acfm @ °F)	540 @ 269°F	540 @ 269°F	540 @ 269°F	540 @ 269°F	940 @ 269°F	1,874 @ 272°F	1,874 272°F
FUEL AND SORBENT DATA							
Coal quality[c]							
Heat content (Btu/lb)	12,030	12,020	12,020	12,010	11,990	12,050	11,910
Volatile matter (percent)	34.0	34.0	34.0	34.0	32.0	35.1	37.0
Ash (percent)	10.62	10.61	10.60	10.68	11.98	12.20	12.14
Moisture (percent)	7.48	7.55	7.56	7.57	7.12	6.49	6.44
Sulfur (percent)	0.86	0.86	0.85	0.85	2.15	2.35	2.35
Nitrogen (percent)	1.70	1.70	1.70	1.70	1.48	1.68	1.68
Coal delivery methods							
Current	Truck/barge	Truck/barge	Truck/barge	Truck/barge	Truck/barge	Truck/barge	Truck/barge
Design	Truck/barge	Truck/barge	Truck/barge	Truck/barge	Truck/barge	Truck/barge	Truck/barge
Likely method for sorbent delivery	Truck/rail	Truck/rail	Truck/rail	Truck/rail	Truck/rail	Truck/rail	Truck/rail
PARTICULATE CONTROL EQUIPMENT DATA							
Type of control	FF	FF	FF	FF	ESP	ESP	ESP
New/retrofit installation	1983	1982	1982	1982	1984	1984	1983
ESP specific collection area (ft^2/10^3 acfm)	N/A[d]	N/A	N/A	N/A	580	580	580
Total plate area (10^3 ft^2)	N/A	N/A	N/A	N/A	756	1512	1512
Emission standards (lb/10^6 Btu)	0.1	0.1	0.1	0.1	0.8	0.8	0.8
PM outlet emissions (lb/10^6 Btu)[e]	0.07	0.09	0.05	0.07	0.04	0.02	0.03
Design coal sulfur (percent)	N/A	N/A	N/A	N/A	1.4	1.4	1.4
Tested efficiency/design efficiency	98.9/99.6	99.1/99.6	99.3/99.6	98.9/99.6	--[d]/99.4	--[d]/99.4	--[d]/99.4

(Continued)

TABLE 4-1. (CONTINUED)

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5	Boiler 6	Boiler 7
NITROGEN OXIDE CONTROL EQUIPMENT DATA							
NO_x control equipment	None	None	None	None	None	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA							
SO_2 control equipment	None	None	None	None	None	None	None
SOLID WASTE DISPOSAL DATA							
Ash transport system type							
Bottom ash	Wet	Wet	Wet	Wet	Wet	Wet	Wet
Fly ash	Dry	Dry	Dry	Dry	Dry	Dry	Dry
Ash disposal method	Off-site Landfill	Off-site Landfill	Off-site Landfill	Off-site Landfill	Off-site Landfill	Off-site Landfill	Off-site Landfill
Existing landfill capacity	15 Years	15 Years	15 Years	15 Years	15 Years	15 Years	15 Years
Estimated distance to off-site waste disposal	5 Miles	5 Miles	5 Miles	5 Miles	5 Miles	5 Miles	5 Miles

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] N/A = Not applicable.

[e] Typical rate based on operating at the annual operating rate.

additive, limestone with and without organic acid additive), lime spray drying, coal switching, and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates.

4.2.1 Lime/Limestone and Lime Spray Drying FGD

4.2.1.1 Control Cases Evaluated--

Table 4-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. Retrofit factors and costs were developed for L/LS FGD only for units 7 and 6. Retrofit of conventional FGD at units 1-5 would be very costly and was not considered as a viable option. Lime spray drying flue gas desulfurization (LSD FGD) retrofit factors and costs were developed only for unit 7. LSD FGD was not considered for units 1-6 in view of the long flue gas runs from these units to where the spray tower could be located. This would make ESP/fabric filter reuse unlikely and result in LSD FGD being very costly. Low cost L/LS FGD cases were developed for units 6 and 7 individually. These units were not combined due to the large size of each unit. For L/LS FGD at unit 7, two 4.0 percent coal sulfur cases were run to compare to the cost estimate provided by Ohio Edison.

4.2.1.2 Layout of Equipment and Design Basis--

Figures 4-2, 4-3, and 4-4 show the general layout and location of the FGD systems. The only space available for construction of an FGD system is south of the unit 5-7 fly ash storage silos in the employee parking lot. If only a scrubber is built for unit 7, a small amount of the north ash pond would need to be filled for locating the waste handling stack out and truck loading areas. If units 6 and 7 are scrubbed, all of the north ash pond area will be needed to locate the waste handling facilities. New employee parking space will have to be made available across the railroad track and the road west of the plant. A new ash pond area would be made available south of the existing ponds by purchasing the property adjacent to the plant.

TABLE 4-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR SAMMIS PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 6	90	2.4	46,200
Boiler 7	90	2.4 and 4.0	39,900[a]
LSD FGD (reuse ESP)			
Boiler 7	64	2.4	28,400
LOW COST CONTROLS			
L/LS FGD			
Boiler 6	90	2.4	46,200
Boiler 7	90	2.4	39,900

[a] For 2.4 percent sulfur coal.

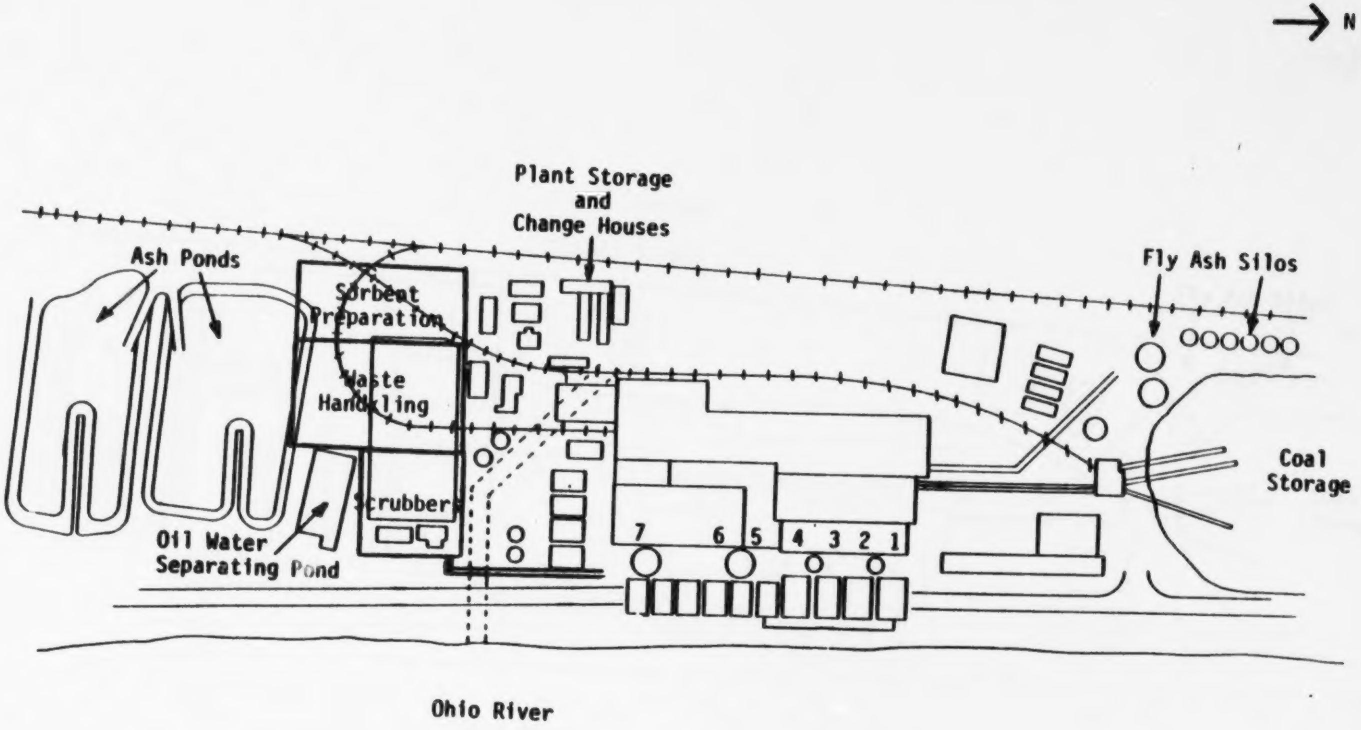

Figure 4-2. Sammis Plant unit 7 L/LS FGD layout.

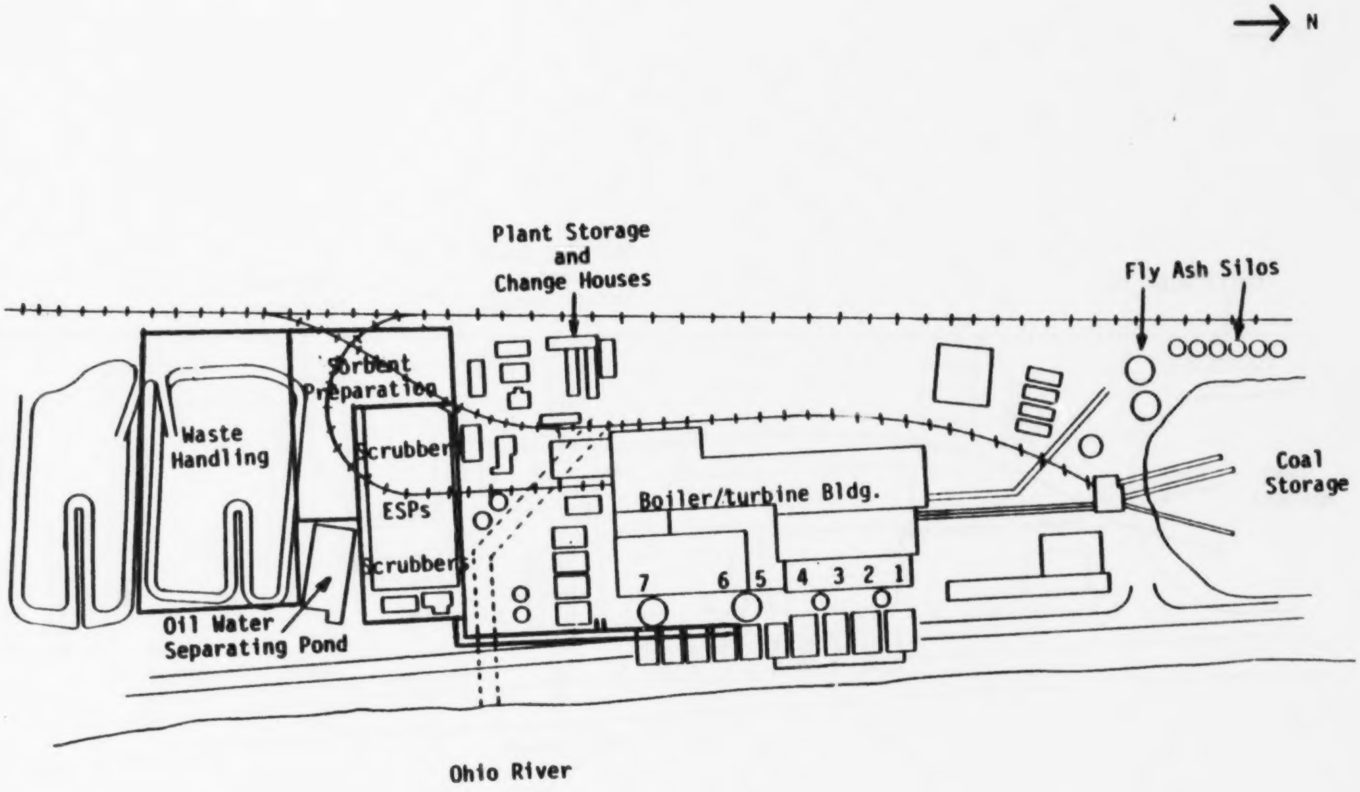

Figure 4-3. Sammis Plant unit 6 and 7 L/LS FGD layout.

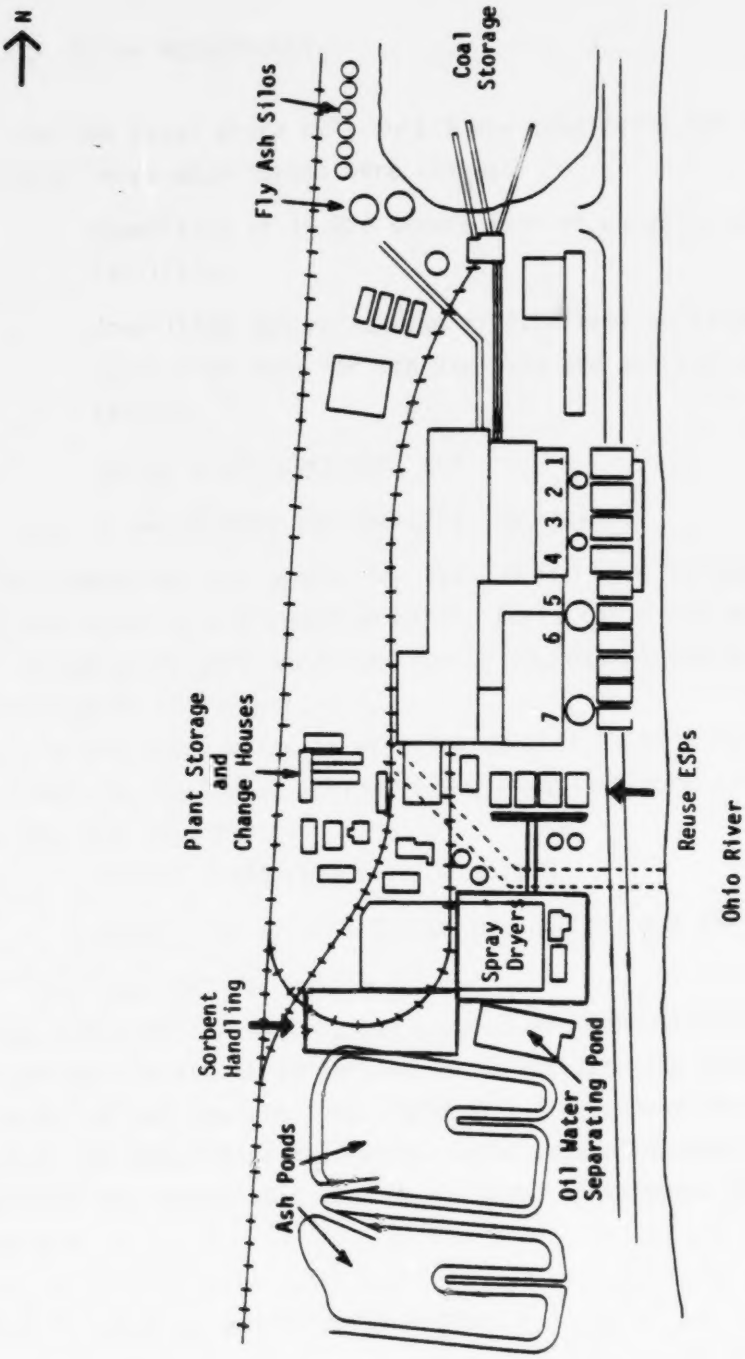

Figure 4-4. Sammis plant unit 7 LSD FGD layout.

4.2.1.3 Scope Adjustments--

For the cases where only unit 7 was considered for FGD retrofit, the following scope adjustments were assumed:

- demolition of 10,000 square feet of existing changehouse facilities,
- demolition and relocation of 4,00 feet of large diameter steel pipe used for ash sluicing and ash sluice water return,
- boiler draft controls, and
- a new chimney for the L/LS FGD cases.

A new chimney was not needed for the LSD FGD case because it was assumed that the existing ESP could be used. Costs for a new employee parking lot and changehouses were accounted for by increasing the general facilities percentage to 15 percent.

For the cases where it was assumed that units 6 and 7 would be scrubbed, the following equipment modifications were assumed in addition to the ones for unit 7:

- boiler draft controls for unit 6,
- demolition of unit 6 flue gas ducting and ESPs, and
- new ESPs for unit 6.

As was the case for unit 7, the general and administrative facilities percentage was set at 15 percent to accommodate the cost of the new employee parking lot and new ash pond. However, changehouse demolition costs and ash sluice line demolition relocation costs were allocated to unit 7. Cost modifications associated with these scope adjustments are summarized in tble 4-3.

4.2.1.4 Location and Retrofit Factors--

The climate and seismic zone location factors for all cases were assumed to be 1.0. The labor and material factor used was 1.06. The soil

TABLE 4-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR SAMMIS PLANT

Scope Adjustment	Description[a]
• New chimney	A new chimney was added for all L/LS FGD cases because reuse of the existing chimney was more expensive ($7.04/kW).
• Modify draft controls	Balanced draft controls were required for all FGD cases ($1.23/kW).
• Building demolition and relocation, duct work demolition, and electrical demolition	Changehouse facilities and steel pipe demolition costs were included for unit 7 FGD case ($4.4/kW), and ESP demolition cost was included for unit 6 FGD case ($30/kW).
• New ash pond, employee parking lot, and changehouses	Costs were included by increasing general facilities to 15 percent.

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

factor used was 1.0, except for the waste handling facilities located on the ash pond area where a factor of 1.03 was assumed.

Retrofit factors adjust for underground obstructions, site access and congestion, and distances to equipment. Tables 4-4 and 4-5 summarize the retrofit factors for the L/LS and LSD FGD cases examined. High underground obstruction factors were used for facilities located between the existing unit 7 ESPs and the existing oil separation pond; small factors were used for those facilities located near or over the ash pond and railroad spurs. High to medium access/congestion factors were assigned to all areas due to the limited space available at the plant site for equipment lay down. High factors were assigned to the SO_2 removal, flue gas handling, and chimney areas because these systems would require use of large cranes which would be severely constrained by the tight site access. Medium factors were assigned to reagent feed, waste handling, and general support equipment due primarily

TABLE 4-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR SAMMIS PLANT

		RETROFIT FACTORS							
		Boiler #6				Boiler #7			
Item	All Units LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.06	1.01	1.15	1.00	1.16	1.01	1.15	1.00	1.16
SO_2 Removal	1.06	1.06	1.50	1.00	1.59	1.06	1.30	1.00	1.38
Flue Gas Handling	1.06	1.06	1.50	2.10	3.34	1.06	1.50	1.50	2.39
Waste Handling	1.09	1.03	1.15	1.01	1.19	1.03	1.15	1.01	1.19
General Support Equipment	1.06	1.12	1.40	1.00	1.57	1.12	1.24	1.00	1.39
SCOPE ADJUSTMENTS									
Wet to Dry Ash System	N/A[f]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Chimney	1.06	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			13					13	
General Facilities - %			15					15	

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 4-6 for distance assumptions.

[e] AGGF = Aggregate Factor.

[f] N/A = Not applicable.

TABLE 4-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR SAMMIS PLANT

Item	All Units LOCF[a]	RETROFIT FACTORS			
		Boiler #7			
		UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.06	1.01	1.15	1.00	1.16
SO_2 Removal	1.06	1.06	1.30	1.00	1.38
Flue Gas Handling	1.06	1.06	1.50	1.85	2.94
General Support Equipment	1.06	1.12	1.24	1.00	1.39
SCOPE ADJUSTMENTS					
New Ash Silo System	N/A[f]	N/A	N/A	N/A	N/A
Chimney	N/A	N/A	N/A	N/A	N/A
Baghouse	N/A	N/A	N/A	N/A	N/A
Demolition	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES					
Engineering - %				13	
General Facilities - %				15	

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 4-6 for distance assumptions used.

[e] AGGF = Aggregate Factor.

[f] N/A = Not applicable.

to the lack of equipment lay-down area. Key distances used in developing retrofit factors are shown in table 4-6. Because the low capital cost L/LS FGD cases for unit 6 and 7 assumes individual units, the retrofit factors for these cases are the same as presented on tables 4-4 and 4-5.

4.2.1.5 Overall Retrofit Factors and Costs--

Table 4-7 presents the overall retrofit factors and costs for all FGD cases. The significantly higher costs for unit 6 versus unit 7 reflect the higher access/congestion factors for unit 6 and the scope adder for demolition and replacement of the unit 6 ESP.

Figures 4-5 and 4-6 summarize the plant level costs versus SO_2 reductions associated with installing L/LS and LSD FGD. The control cost case presented in Figure 4-5 is for lime FGD system costs. The low cost LS FGD curve shows the impact of scrubber optimization by eliminating spare towers and moximizing the tower size and use of adipic acid additives to minimize the capital cost.

The application of L/LS FGD at units 6 and 7 would reduce plant level SO_2 emissions by approximately 86,000 tons per year assuming a 90 percent level of control is achieved. Unit 7 is the most cost effective unit because its FGD system capital costs are significantly less than unit 6. The application of LSD FGD on unit 7 would reduce plant level emissions by 28,400 tons per year.

4.2.1.6 Comparison to Utility Cost Estimates--

Ohio Edison provided the cost results from a Gilbert/Commonwealth study for retrofit of L/LS FGD on unit 7. The FGD system layouts and cost estimates were based on conceptual engineering and budget estimates from

TABLE 4-6. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR SAMMIS PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
L/LS FGD				
Boiler 6	1175	75	100	200
Boiler 7	575	75	100	200
LSD FGD (reuse ESP)				
Boiler 7	500	500	100	N/A[c]

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

TABLE 4-7. L/LS AND LSD FGD COSTS FOR SAMMIS PLANT
(August 1987 Dollars)

		IAPCS Retrofit Costs[a]		
Case Description	Overall Retrofit Factor	Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 6	3.01	316.4-382.7	1,397-1,609	24.2-27.9
Boiler 7	1.86	205.1-246.9	1,122-1,290	19.5-22.4
LSD FGD (reuse ESP)				
Boiler 7	1.93[b]	156.2	1,012	12.5
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boiler 6[c]	3.01	242.9	1,010	17.5
Boiler 7[c]	1.86	157.2	811	14.1

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] No plate area increase needed.

[c] Based on lim slurry with MgO addition.

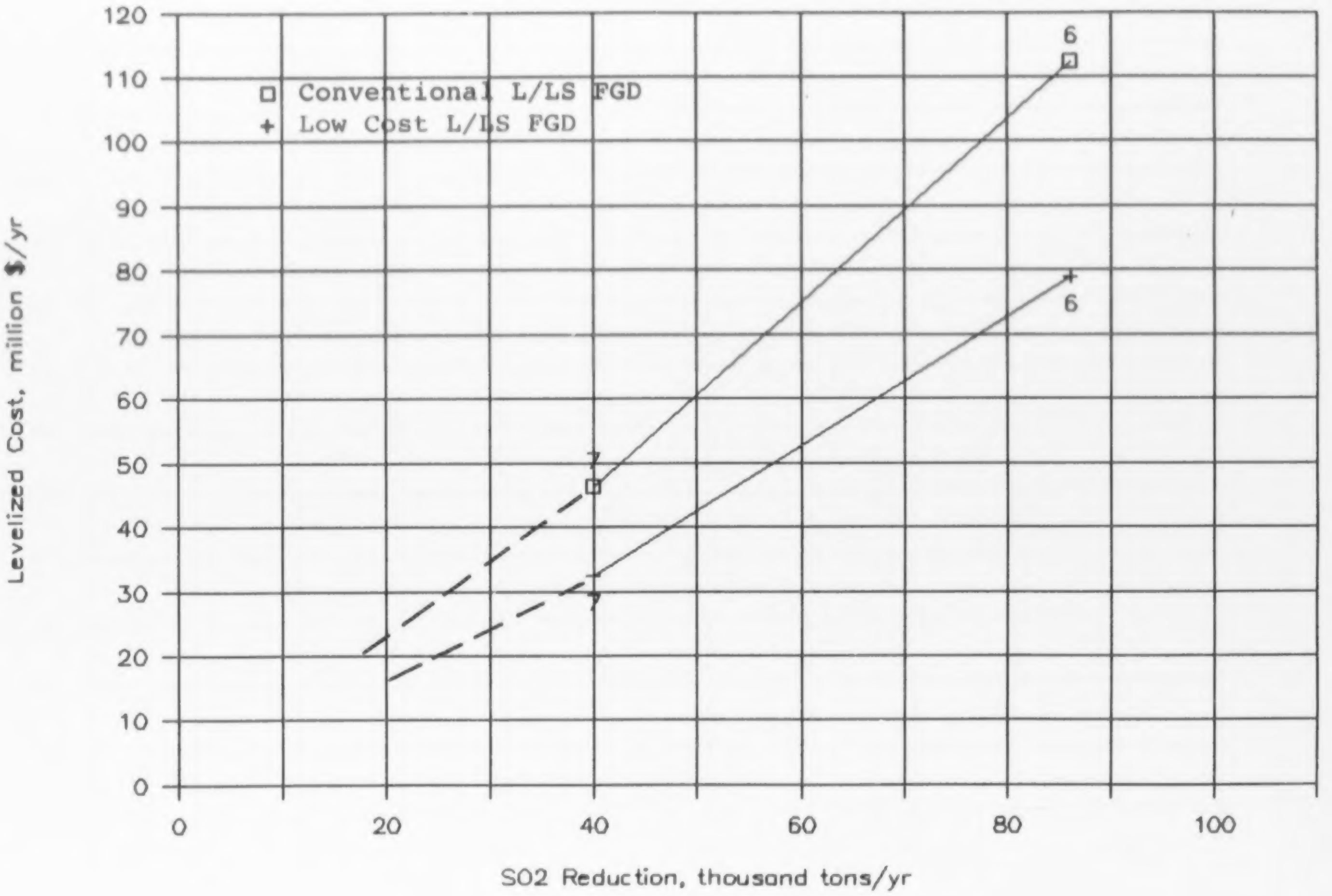

Figure 4-5. Sammis Plant L/LS cost versus SO_2 reduction.

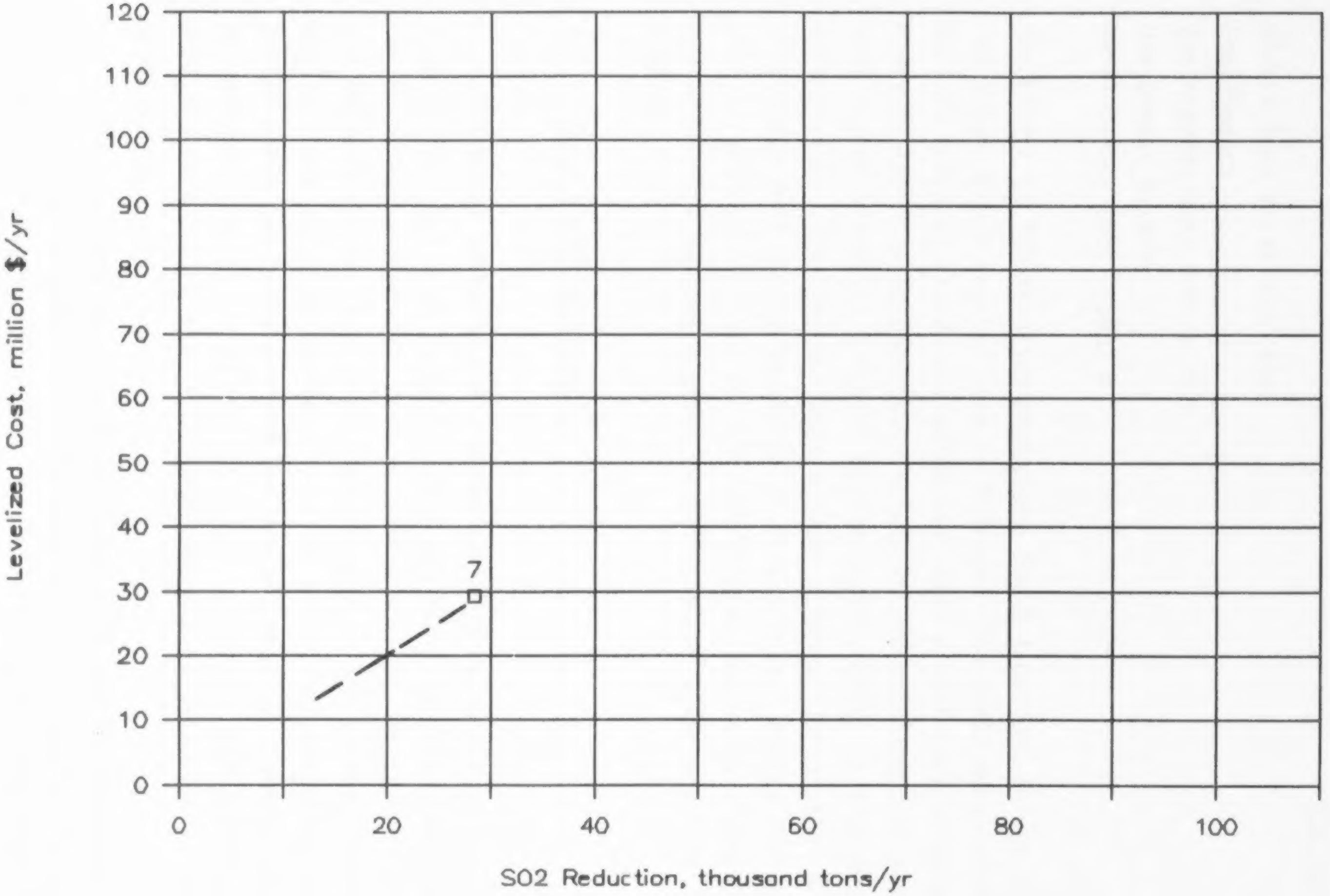

Figure 4-6. Sammis Plant lime spray dryer FGD cost versus SO_2 reduction.

major component suppliers based on a 4 percent sulfur coal. Key capital cost components were:

	Capital Costs - $/kW
Direct Cost Materials/Labor	263
Contingency	58
Engineering/Home office fees	67
Management Reserve	55
Total Direct Cost - 1987 $	443

The EPRI L/LS FGD detailed procedures for a 4 percent sulfur coal estimated the total direct capital cost at $327/kW. The IAPCS model using the EPRI-derived retrofit factor estimated the total direct cost at $262/kW. However, the Ohio Edison costs include an inconel-lined new chimney which adds $74/kW and waste disposal system capital costs of $26/kW to the total direct cost. The EPRI estimate assumes a new acid resistant brick chimney which only adds $14/kW to the total direct cost. Adding the incremental cost of an inconel liner for the new chimney and waste disposal to the EPRI and IAPCS cost estimates gives an EPRI cost of $420/kW and an IAPCS cost of $355/kW.

4.2.2 Coal Switching/Blending

Presented in table 4-8 are the coal and ash analyses for the existing high sulfur coal used in boilers 5-7 and the alternative coal used to evaluate coal switching. Coal switching was not considered for boiler units 1-4 because the existing coal used already is low-sulfur. Since no ash analysis was provided by the plant, the impacts of switching coal on the boiler could not be determined for boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. ESP performance impacts were evaluated using the IAPCS model which estimated that no ESP modifications were required.

Figure 4-7 presents the plant level cost and SO_2 emission reduction for coal switching at units 5-7. The lower curve corresponds to a 1985 fuel cost differential of $10.44 per ton between the existing coal ($34.45/ton)

TABLE 4-8. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR SAMMIS PLANT

	Existing Coal	Switch Coal	Cleaned Coal
Item	Boilers 5-7	Boilers 5-7	Boilers 5-7
COAL PARAMETERS			
Percent Sulfur	2.4	0.89	1.7
Percent Ash	11.8	16.6	6.1
Btu Per Pound	12,053	12,058	12,917
ESP PARAMETERS			
Existing/Needed SCA[a]	580	580	580

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

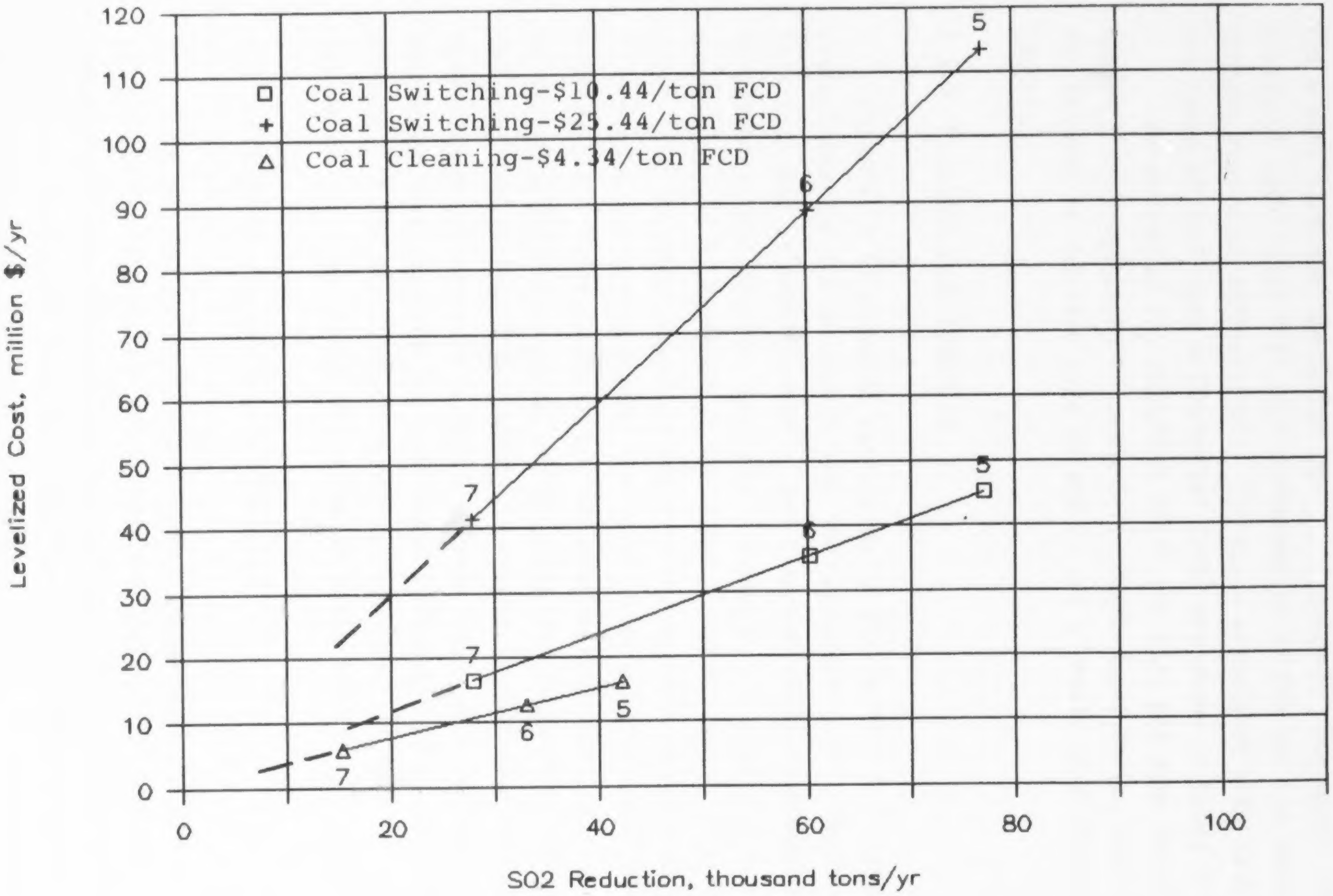

Figure 4-7. Sammis Plant coal switching/cleaning costs versus SO_2 reduction.

and a West Virginia low-sulfur coal ($44.89/ton). The upper curve shows the impact of additional fuel cost differential of $15 per ton added to the current fuel cost differential. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 4-9.

An estimated SO_2 reduction of 77,000 tons per year would result from applying coal switching to units 5-7. Differences in the cost-effectiveness for boilers of the same size (6 and 7) are a result of different capacity factors.

4.2.3 Physical Coal Cleaning

Physical coal cleaning was evaluated for boilers 5-7 using coal characteristics for an Appalachian medium-sulfur coal. The cost of cleaning this coal was estimated using a coal cleaning model developed by TVA. It was assumed that the coal would be cleaned at the mine and no refuse disposal would be required at the plant. The cleaned coal parameters were input into the IAPCS model to estimate performance impacts on the ESPs.

Figure 4-7 also presents the results for physical coal cleaning on boilers 5-7. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal. The costs do include the estimated increase in coal cost for the cleaning operation $4.34 per ton). No ESP upgrade costs were needed. It was estimated that cleaning the coal could reduce the plant SO_2 emissions by 35 percent (42,200 tons/yr) at an average unit cost of $384 per ton. Cost estimates for each boiler are shown in table 4-10.

4.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost and performance estimates for SO_2 control technologies that are under development, but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercial technologies because the cost/performance estimates have a higher degree of uncertainty due to the lack of commercial data. The following control technologies were evaluated:

TABLE 4-9. COAL SWITCHING COSTS FOR SAMMIS PLANT
(August 1987 Dollars)

		@ \$10.44/ton FCD		@ \$25.44/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
5	16,800	584	7.1	1,467	17.8
6	32,300	585	7.1	1,471	17.8
7	27,900	591	7.2	1,484	18.0
5-7	77,000	587	7.1	1,474	17.9

TABLE 4-10 PHYSICAL COAL CLEANING COSTS FOR SAMMIS PLANT
(August 1987 Dollars)

Boiler	SO_2 Reductions (tons per year	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
5	9,200	381	2.5
6	17,700	382	2.5
7	15,300	386	2.6
5-7	42,200	384	2.5

furnace sorbent injection (FSI) at boilers 1-7, duct spray drying (DSD) at boilers 1-7, and repowering life extension at boilers 1-4.

4.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. As such, many retrofit costs are built into the base case design and costs. Retrofit factors developed for these technology options focus on scope adders that are not included in developer's assumptions. Basic assumptions and cost adjustments made for FSI and DSD are presented in table 4-11.

4.3.1.1 Furnace Sorbent Injection--

FSI retrofit factors were developed for all boilers. The sorbent was assumed to be a prepared calcitic hydrate material with the receiving/storage facilities located just south of the existing boiler 5-7 ash silo area. This area is presently the east section of the employee parking lot and employee changeroom area. This area was chosen because of its access to existing roads and railroad spur and because it minimizes solids conveying distances.

Approximately 800 to 1,400 feet of sorbent conveying line would be required to reach the injection day bins for boilers 7 through 1, respectively. The additional solid waste storage silos were located adjacent to the sorbent preparation area to allow for recycle of spent sorbent. It was assumed that the alkaline waste material could be disposed of at the existing offsite landfill.

Because the ESPs for boilers 5-7 were recently installed and have large SCAs of 580, the existing ESPs were estimated to be adequate for particulate control with flue gas humidification. Solid waste collected in the existing ESPs would also be conveyed to the existing fly ash silos. The fabric filters on boilers 1-4 should also be able to handle the additional solids loading caused by FSI. Solids collected by the baghouses would be conveyed to the ash silos at units 1-4 and disposed of in the existing off-site landfill.

TABLE 4-11. SCOPE ADJUSTMENTS FOR FSI AND DSD AT SAMMIS PLANT

Item	Boiler 1-4	 5	 6-7
BASIC ASSUMPTIONS			
Approximate access/congestion rank	Low	Low	Low
Can the existing ESP/FF be upgraded?	Yes	Yes	Yes
Was a new baghouse evaluated for DSD	No	No	No
SCOPE ADDERS			
Install dry ash handling system	No	No	No
New Stack	No	No	No
Additional duct work (ft)	0	0	0
Duct demolition length (ft)	50	50	50
Building demolition area (ft^2)	0	0	0
ADDER COSTS AND RETROFIT FACTOR SUMMARY			
Scope adder costs for reuse baghouse (10^3 \$)[a]	46	N/A[b]	N/A
Scope adder costs for ESP reuse (10^3 \$)[a]	N/A	68	118
ESP upgrade retrofit difficulty factor (for plate area addition)	N/A	1.55	1.55

[a] June 1985 dollarls.

[b] N/A = Not applicable.

4.3.1.2 Duct Spray Drying--

Duct spray drying using a slurried calcium-based sorbent was evaluated for retrofit at boilers 1-7. The sorbent receiving/storage/conveying systems would be the same as for FSI. Also as with FSI, the existing ESPs for boilers 5-7 and baghouses on boilers 1-4 should be satisfactory for particulate removal.

Major process parameters associated with the performance of DSD are sufficient duct residence time necessary to obtain good SO_2 capture and adequate flue gas temperature available for evaporation of the slurry. Duct residence times for all boilers should be quite sufficient due to the long duct runs to the existing particulate control equipment.

All the boilers have an air heater flue gas outlet temperature of $300^{\circ}F$. For boilers 5-7, it was estimated that a 42 percent reduction of SO_2 could be achieved. For boilers 1-4, it was estimated that a 68 percent reduction of SO_2 could be achieved. The increase in removal efficiency for boilers 1-4 versus 5-7 is due to reusing the fabric filters versus ESPs.

4.3.1.3 Overall Retrofit Factors and Costs--

Table 4-12 presents the estimated retrofit costs for FSI and DSD. Figure 4-8 shows the costs of retrofitting FSI and DSD versus the plant level SO_2 reductions achieved. For FSI technology two curves were generated to present the range of anticipated SO_2 removal (50 and 70 percent) and sorbent utilization (25 and 35 percent) potential. If 50 percent removal is achieved at units 1-7, an overall plant level reduction of 72,100 tons per year of SO_2 would result. If 70 percent removal is achieved, the resulting plant level SO_2 reduction is estimated to be 101,000 tons per year. Applying DSD to all boilers would result in an annual reduction of 65,500 tons per year of SO_2.

4.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG)

Boilers 1-4 are potential candidates for life extension through FBC/CG because they are less than 300 MW in size and have been in service over 25

TABLE 4-12. RETROFIT COSTS FOR FSI AND DSD FOR SAMMIS PLANT (August 1987 Dollars)

Case Description	IAPCS Captial Cost (\$/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost (\$/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50 % removal)[a]				
Boiler 1	22.3	3.4	954	2,500
Boiler 2	22.3	3.3	939	2,500
Boiler 3	22.3	3.2	896	2,700
Boiler 4	22.3	2.8	797	3,200
Boiler 5	47.6	7.2	747	13,300
Boiler 6	34.8	6.3	659	25,700
Boiler 7	34.8	6.7	691	22,200
Furnace Injection (70 % removal)[b]				
Boiler 1	22.9	3.7	736	3,500
Boiler 2	22.9	3.6	725	3,500
Boiler 3	22.9	3.5	693	3,800
Boiler 4	22.9	3.1	622	4,500
Boiler 5	48.2	7.3	540	18,600
Boiler 6	35.3	6.4	476	35,900
Boiler 7	35.3	6.7	499	31,000
Duct Spray Drying (ESP/fabric filter reuse)				
Boiler 1	25.4	5.2	1,071	3,300
Boiler 2	25.4	5.1	1,052	3,400
Boiler 3	25.4	4.8	998	3,600
Boiler 4	25.4	4.2	875	4,300
Boiler 5	38.9	5.3	666	11,000
Boiler 6	32.3	4.4	551	21,400
Boiler 7	32.3	4.8	598	18,500

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

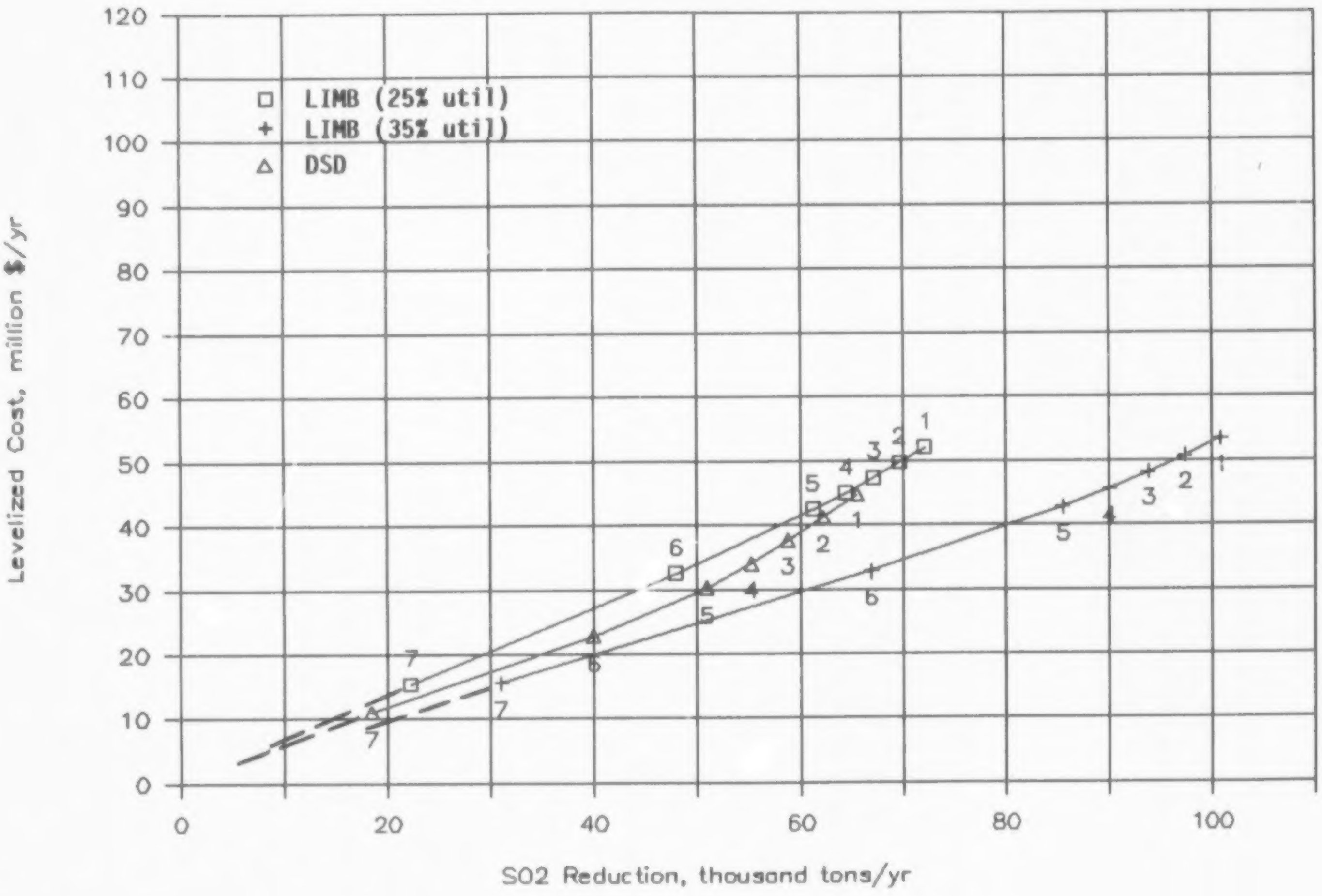

Figure 4-8. Sammis Plant FSI/DSD cost versus SO_2 reduction.

years. However, these boilers are more likely candidates for continued use on low-sulfur coals because:

- they have good heat rate and as such are base load units,
- construction access to these boilers is extremely limited, and
- the plant site near the boiler is very congested, preventing the installation of major equipment items.

4.4 NO_x CONTROL TECHNOLOGIES

Boilers 1-4 are equipped with front-wall circular burners while boilers 5-7 have opposed-wall cell burners. Boiler 5 has already been retrofit with low NO_x burners. NO_x controls evaluated at the Sammis plant include low NO_x burners at boilers 1-4 and 6-7 and selective catalytic reduction at boilers 1-7.

4.4.1 Low NO_x Burners.

Low NO_x burners are available for the type of circular burners on boilers 1-4. However, these units are very compact and have intense combustion zones. For example, the burner heat input (approximately 120 million Btu/hr) relative to the furnace depth (approximately 24 feet) and height above the top burner row (22 feet) is quite high for wall-fired circular burners. Thus, flame impingement on the rear furnace wall and/or superheater tube surfaces could be a problem. The vertical burner spacing (approximately 7 feet) is also relatively tight and could result in more flame interaction. Carbon burnout problems could also occur as the non-volatile fraction of the boiler heat input flux (approximately 280 Btu/sec-ft^2) relative to the bulk furnace residence time (1.9 seconds) and the upper furnace residence time (0.7 seconds) is intermediate to high. Based on these considerations, the NO_x reduction performance of a LNB retrofit at Sammis 1-4 is estimated to be low-to-intermediate (25-35 percent). This is due primarily to the relatively small furnaces and high excess air operating level (to avoid slagging).

Sammis boilers 6 and 7 are opposed wall-fired units with cell burners. Several utility boilers with cell burners, including Sammis 5, are currently undergoing commercial demonstration of low NO_x burners, but data on emission reductions are not available. Because of its physical design, Sammis 5 is a better candidate for LNB retrofit than Sammis 6 and 7 and thus is likely to exhibit higher NO_x reduction performance. For example, the Sammis 5 burner heat input (approximately 60 million Btu/hr, counting each individual burner within a cell) relative to the furnace depth (approximately 24 feet) and height above the top burner row (approximately 22 feet) is the lowest of all the cell burner-equipped units in Ohio examined in this study (Sammis 5-7, Muskingum 5, and Stuart 1-4). Also, the furnace volumetric heat release rate (approximately 20,000 Btu/hr ft^3), the burner zone heat release rate (360,000 Btu/hr ft^2), and the non-volatile fraction of the boiler heat input flux (approximately 270 Btu/sec-ft^2) relative to the bulk furnace residence time (approximately 2.4 seconds) and the upper furnace residence time (approximately 1.3 seconds) are quite low. Sammis 6 and 7 have much tighter furnaces than Sammis 5 (values for Sammis 5 are 50-80% of those for Sammis 6 and 7) and are therefore likely to have lower NO_x reduction performance from LNB retrofit.

No current slagging problems were identified for Sammis 5-7. Slagging potential on unit 5 based on the steam generation rate per furnace plan area (1,100 lb/hr ft^2) is well below levels frequently associated with slagging (1,300-1,500). However, Sammis 6 and 7 have a slagging factor of 1,700 lb/hr-ft^2 which indicates they would be more susceptible to furnace slagging problems than Sammis 5.

Based on these considerations, the NO_x reduction performance of a LNB retrofit at Sammis 6-7 is estimated to be intermediate (30-40 percent), slightly higher than that for Sammis 1-4. This is due to Sammis 6-7 being less likely to experience potential rear wall and superheater/reheater flame impingement problems than Sammis 1-4. Total NO_x reductions and retrofit control costs for a LNB retrofit at Sammis 5 were not estimated as that unit is already equipped with low NO_x burners. However, using the above methodology, the estimated retrofit LNB performance at Sammis 5 would be the maximum, 50 percent NO_x reduction.

4.3.2 Selective Catalytic Reduction

Two SCR configurations were used at the Sammis Plant. Because boilers 1-6 have no space to locate the tail end SCR system, it was assumed that the catalytic reactors would be located where the abandoned ESPs are now located. For this configuration, hot flue gas would be ducted to the catalytic reactors from the economizer. The SCR system configuration selected for Sammis unit 7 was the tail end SCR with flue gas preheat. This system was selected because the catalytic reactors could be located adjacent to the retrofit ESPs. Table 4-13 summarizes the key information used to develop the SCR unit retrofit difficulty and scope adjustments.

4.4.3 Summary of NO_x Control Costs

Table 4-14 and Figure 4-9 show the annual cost of NO_x control. The LNB curve assumes 35 percent NO_x reduction is achievable at Sammis 1-4 boilers and 40 percent NO_x reduction at Sammis 6-7, resulting in a reduction of 13,200 tons per year of NO_x. The unit cost of a LNB retrofit was estimated as \$407 - \$527 per ton of NO_x for boilers 1-4 and \$194 - \$224 per ton for boilers 6-7.

Total annual NO_x reductions from retrofit of SCR on all seven units is 32,500 tons per year. Cost-effectiveness values range from \$2,242 on unit 7 with a tail-end SCR and an asumed catalyst life of 3.5 years to \$5,048 on unit 1 with the SCR between the economizer and air heater and a catalyst life of one year. These cost do not include down time penalties (replacement power incremental costs) for units 1-6.

TABLE 4-13. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR SAMMIS PLANT

Item	Boiler 1-6	Boiler 7
Site access and congestion for SCR reactor	High	Medium
SCOPE ADDER PARAMETERS		
Building demolition (1,000$)	0	30
Ductwork demolition (1,000$)	0	104
New duct length (feet)	0	600
New duct costs (1,000$)	0	8,480
New heat exchanger (1,000$)	0	5,461
Total scope adder costs (1,000$)	0	14,075
Retrofit factor for SCR	1.60	1.34
General facilities (percent)	10	25

TABLE 4-14. NO_X CONTROL COSTS FOR SAMMIS PLANT
(August 1987 Dollars)

NO_X Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	ANNUAL COST (mills/kWh)	NO_X REDUCED (tons/year)
Low NO_x Burner	1	35	15.2	527	0.8	1,000
	2	35	15.2	515	0.8	1,000
	3	35	15.2	482	0.7	1,100
	4	35	15.2	407	0.6	1,400
	6	40	7.4	194	0.3	4,600
	7	40	7.4	224	0.4	4,000
Selective Catalytic Reduction	1	80	141.4	5,048	17.4	2,400
	2	80	141.4	4,940	17.0	2,400
	3	80	141.4	4,632	16.0	2,600
	4	80	141.4	3,937	13.6	3,100
	5	80	121.3	4,094	14.2	4,800
	6	80	103.8	3,992	13.8	9,200
	7	80	89.8	2,242	7.8	8,000

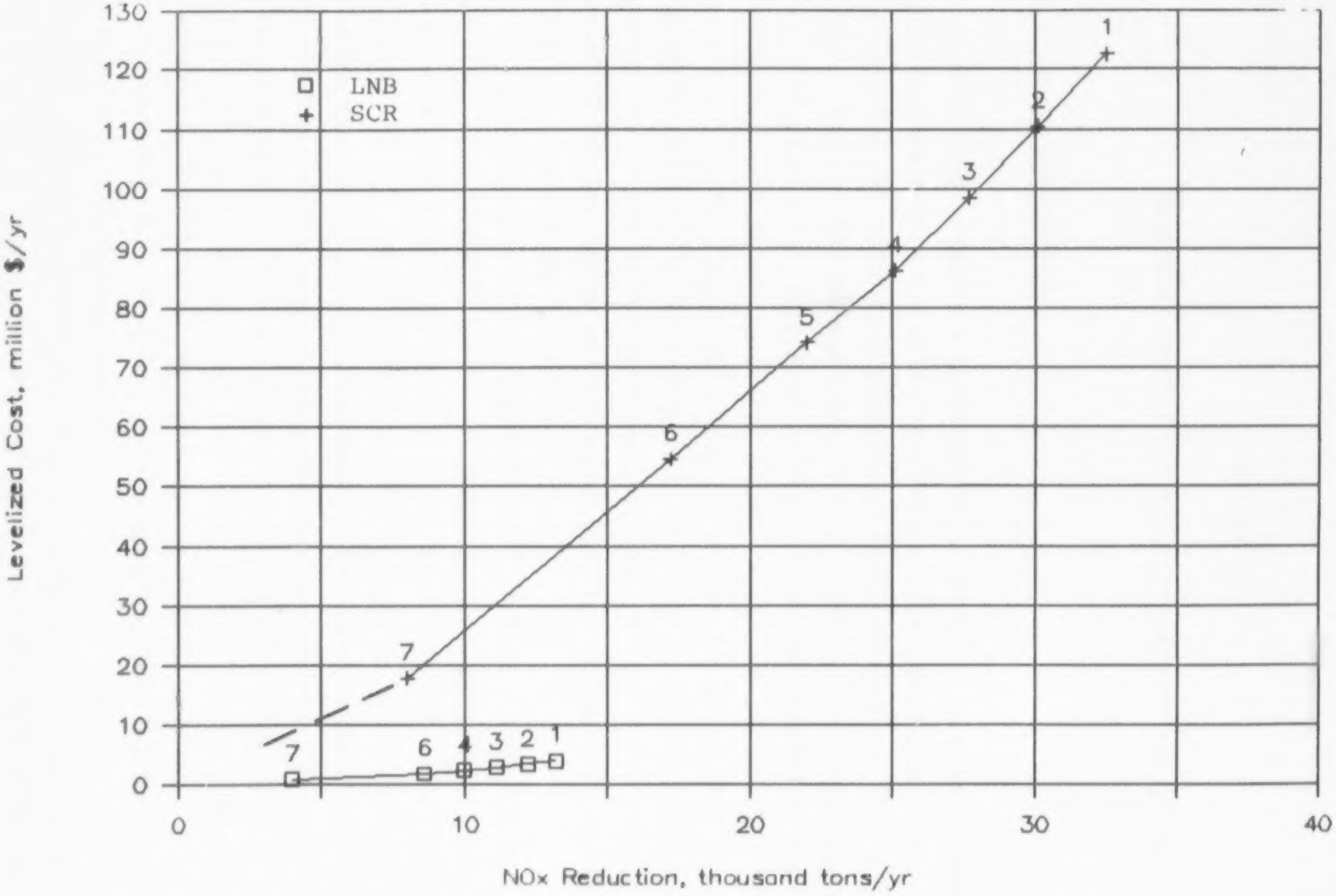

Figure 4-9. Sammis Plant NO_x controls cost versus NO_x reduction.

SECTION 5

MUSKINGUM RIVER PLANT RETROFIT FACTORS AND COSTS

5.1 PLANT DESCRIPTION

Ohio Power Company's Muskingum River plant is located in southeastern Ohio, approximately two miles northwest of the town of Beverly. The plant has a total net generating capacity of 1,425 megawatts. Figure 5-1 shows the location of the five boilers, control systems, and other equipment. As the plot plan shows, the plant is adjacent to and bounded on the northwest, north, and east by the Muskingum River. A portion of the plant's southern boundary adjoins a major metallurgical processing plant with county Highway 32 delineating the southwestern line of the plant site. The overall topography of the surrounding area is steep rolling hills. Table 5-1 presents the key design and operating data for the Muskingum Plant obtained from EIA Form 767 and the plant visit.

The majority of the plant property is actively used for coal storage (approximately 730,000 tons/60-70 days of normal operation), electrical substation and transmission facilities, and ash ponds. Coal is received by conveyor across the river from an Ohio Power mine and wash plant and is stored in a single pile located next to the river along the northwest side of the plant site. Coal storage at the wash plant is limited to a short-term working pile. All units burn a high-sulfur washed coal (4.4-5.0 percent) which comes from local mines. Coal ash analysis and washability data for the coal were not available.

Generating units 1-4 are located approximately 400 feet east of the coal pile at the northern end of the plant site. Unit 1, the northernmost unit, is located approximately 50 feet south of the flood control dike on the river. Units 2-4 are located adjacent to and immediately south of unit 1, forming a straight line running from north to south. Coal handling, turbine generators, and cooling equipment for all units plus power

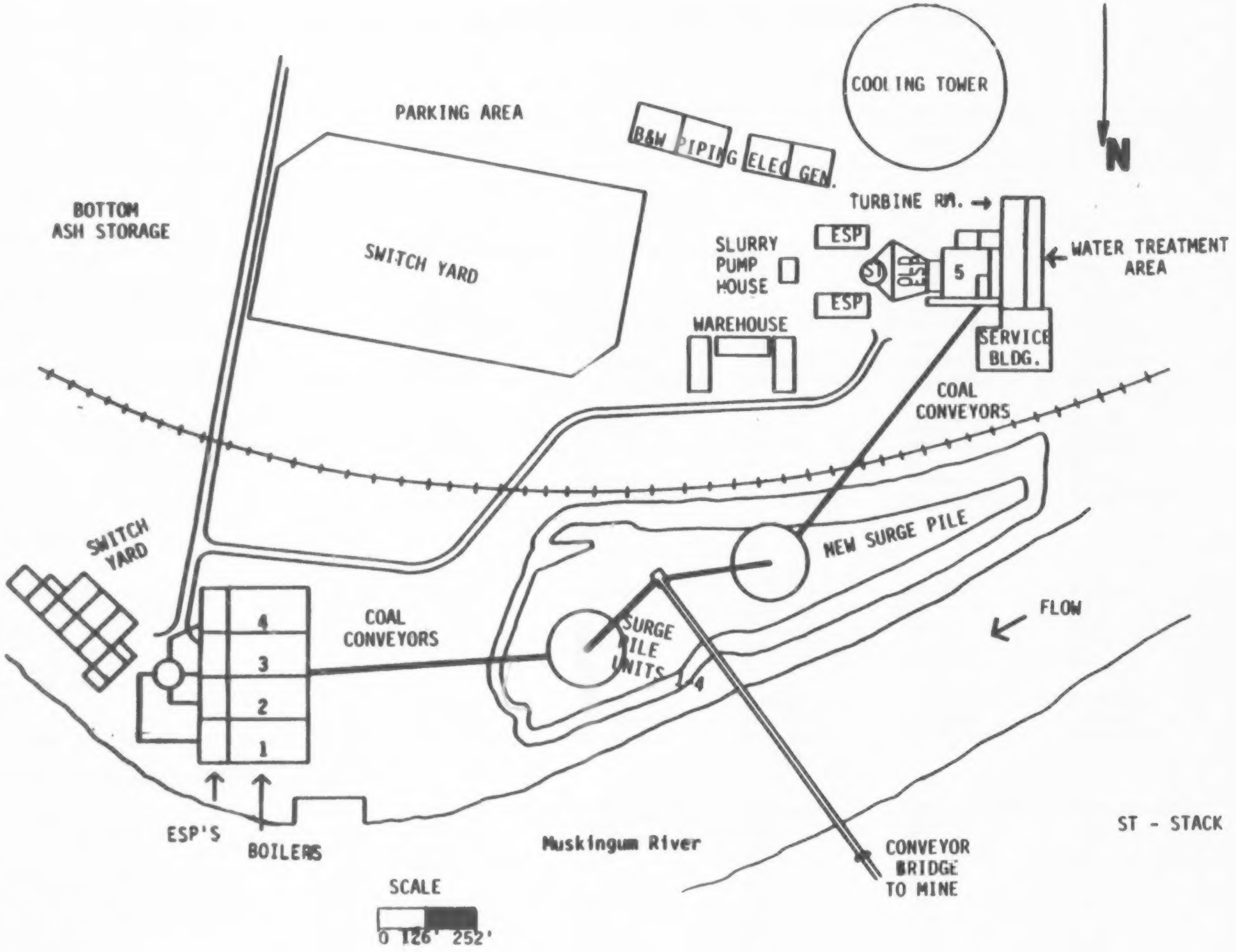

Figure 5-1. Muskingum River plant plot plan.

TABLE 5-1. KEY DESIGN AND OPERATIONAL DATA FOR MUSKINGUM PLANT

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5
BOILER AND STACK DATA					
Net generating capacity (MW)	205	205	215	215	585
Boiler manufacturer	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox
Installation date	1953	1954	1957	1958	1968
Capacity factor (10 year projected)	41.4	59.5	59.4	49.1	58.8
Heat rate (Btu/kW-hr)	1,875	1,875	2,001	2,001	5,291
Boiler type/firing type/bottom type	Front wall/ wet	Front wall/ wet	Cyclone/ wet	Cyclone/ wet	Opposed wall/dry
Boiler dimensions, (ft, D x W x H^a)	32x56x60	32x56x60	32x22x50	32x22x50	39x63x91
Burner type/number of burners (# EL x #/EL)	Circular/3x16	Circular/3x16	Cyclone/2x2.5	Cyclone/2x2.5	Circular/5x10 Cell/3x16.7
Burner spacing (vert x horiz, ft)	3.75x--^{b}	3.75x--^{b}	12x--^{b}	12x--^{b}	14x--^{b}
Burner zone heat release rate (BTU/hr-ft^2)	263,000	263,000	501,000	501,000	552,000
Excess air	15	15	10	10	20
Draft type	Forced	Forced	Forced	Forced	Forced
Flue gas flow rate (1000 acfm @ °F)	770 @ 335°F	770 @ 335°F	870 @ 340°F	870 @ 340°F	2,100 @ 305°F
FUEL AND SORBENT DATA					
Coal quality^c					
Heat content (Btu/lb)	11,420	11,390	11,400	11,410	11,510
Volatile matter (percent)	27.7	27.7	27.7	27.7	27.8
Ash (percent)	12.3	12.3	12.3	12.3	12.2
Moisture (percent)	8.5	8.5	8.5	8.5	8.5
Sulfur (percent)	4.4	4.4	4.4	4.4	4.4
Coal delivery methods					
Current	Conveyor	Conveyor	Conveyor	Conveyor	Conveyor
Design	Conveyor	Conveyor	Conveyor	Conveyor	Conveyor
Likely method for sorbent delivery	Rail/truck	Rail/truck	Rail/truck	Rail/truck	Rail/truck
PARTICULATE CONTROL EQUIPMENT DATA					
Type of control	ESP/cold side	ESP/cold side	ESP/cold side	ESP/cold side	ESP/cold side
New/retrofit installation	1972	1972	1972	1971	1980
ESP specific collection area (ft^2/10^3 acfm)	202	202	177	177	424
Total plate area (10^3 ft^2)	161.3	161.3	161.3	161.3	891
Emission standards (lb/10^6 Btu)	0.1	0.1	0.1	0.1	0.1
ESP outlet emissions (lb/10^6 Btu)^d	.06	.09	.10	.09	.03
Design coal sulfur (percent)	5.4	5.4	4.5	4.5	5
Gas conditioning	None	None	None	None	None
Tested efficiency/design efficiency	99.7/98.5	99.7/98.6	97.5/98.5	97.5/98.5	99.4/99.4

(Continued)

TABLE 5-1. (CONTINUED)

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5
NITROGEN OXIDE CONTROL EQUIPMENT DATA					
NO_X control equipment	None	None	None	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA					
SO_2 control equipment	None	None	None	None	None
SOLID WASTE DISPOSAL DATA					
Ash transport system type					
Boiler bottom ash	Wet	Wet	Wet	Wet	Wet
Fly ash	Wet	Wet	Wet	Wet	Wet
Ash disposal method	On-site	On-site	On-site	On-site	On-site
Existing pond capacity	17 years	17 years	17 years	17 years	17 years
Estimated distance to off-site waste disposal	N/A[e]	N/A	N/A	N/A	N/A

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

[e] N/A = Not applicable.

transmission lines for unit 4 fill the area between the coal pile and the boiler structure. The ESPs are located to the east of each boiler and flue gas from these units is ducted to a common stack. The electrical substation for units 1-3 and 138 KV high-voltage overhead transmission lines are located immediately east of the ESPs. Bottom ash is wet sluiced to disposal areas located to the east and south of the substation. Fly ash from the ESPs is wet sluiced underground along the south side of the boiler structure and then southwesterly to a common sluice pump house located behind unit 5.

Generating unit 5 is located approximately 600 feet southwest of the coal pile along the western edge of the plant site. County Highway 32 is immediately south of the unit and the main electrical substation for the plant is approximately 200 feet to the east. The turbine-generator and administrative/maintenance facilities are located on the west side of the boiler structure. The cooling tower is to the south. Dual ESPs (each handling one-half of the boiler flue gas), the stack for unit 5, and the fly ash sluice pumping equipment for units 1-5 are located to the east. Relatively open areas are available to the southeast and north of the boiler/ESP. The original air heater and ESP (no longer in use) were abandoned in place when the current air heater and ESP were installed and occupy space between the boiler structure and stack.

5.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

The following commercial SO_2 control technologies were evaluated at the Muskingum River Plant: lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, and coal switching. The following discussion presents the retrofit issues and cost/performance estimates.

5.2.1 Lime/Limestone and Lime Spray Drying FGD

5.2.1.1 Control Cases Evaluated--

Table 5-2 lists the limestone/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. For L/LS

TABLE 5-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR MUSKINGUM RIVER PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur Wt %	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	4.4	38,400
Boiler 2	90	4.4	38,200
Boiler 3	90	4.4	36,100
Boiler 4	90	4.4	35,200
Boiler 5	90	4.4	106,800
LSD FGD (reuse ESP)			
Boiler 5	58	4.4	69,000
LSD FGD (new baghouse)			
Boiler 1	82	4.4	35,200
Boiler 2	82	4.4	35,000
Boiler 3	87	4.4	34,700
Boiler 4	87	4.4	33,800
Boiler 5	76	4.4	90,400
LOW COST CONTROLS			
L/LS FGD			
Boilers 1-4 (combined)	90	4.4	147,900
Boiler 5	90	4.4	106,800

FGD, individual unit control cases on boilers 1 through 5 were evaluated. For the low cost FGD scenarios, a combined control case on boilers 1-4 and an individual control case for 5 were evaluated. Unit 5 was not combined with units 1-4 because unit 5 is not located near units 1-4. For LSD FGD, existing ESPs for boiler 5 have adequate SCA (424 $ft^2/10^3$ acfm) and are located such that duct runs to and from the spray dryer absorbers would not be long or difficult to install. Therefore, both LSD with ESP reuse and LSD with a new fabric filter were examined for unit 5. However, boiler 1-4 ESPs are small (<210 SCA), and have limited space for ESP upgrading. Therefore, only LSD FGD with new fabric filters was evaluated for these units.

5.2.1.2 Layout of Equipment and Design Basis--

Figure 5-2 shows the general layout and location of the L/LS FGD control systems. Due to spatial constraints around the existing stacks for boilers 1-4, the FGD system was located on the bottom ash sluice pond behind these units. Once this pond is backfilled, ample space will be available for FGD control equipment for units 1-4. The reagent receiving equipment will be located along the rail spur. The cost of upgrading the rail spur is accounted for by increasing general facilities. To minimize duct runs, a new chimney will be installed (for units 1-4) near the scrubber flue gas outlet. For unit 5, the FGD control equipment will be located directly behind the ESPs. The existing chimney will be lined and reused. For the low cost case, units 1 through 4 are combined and share common process areas and chimney.

Figure 5-3 shows the equipment layout for the LSD FGD cases. As with the L/LS FGD system, the spray dryer equipment for units 1 through 4 will be located on the backfilled bottom ash pond. For these units it is assumed that the existing ESPs would not be used because they are remotely located from the spray dryer vessels and would not be able to handle the increased solids loading. Thus, for units 1 through 4, new baghouses will be erected

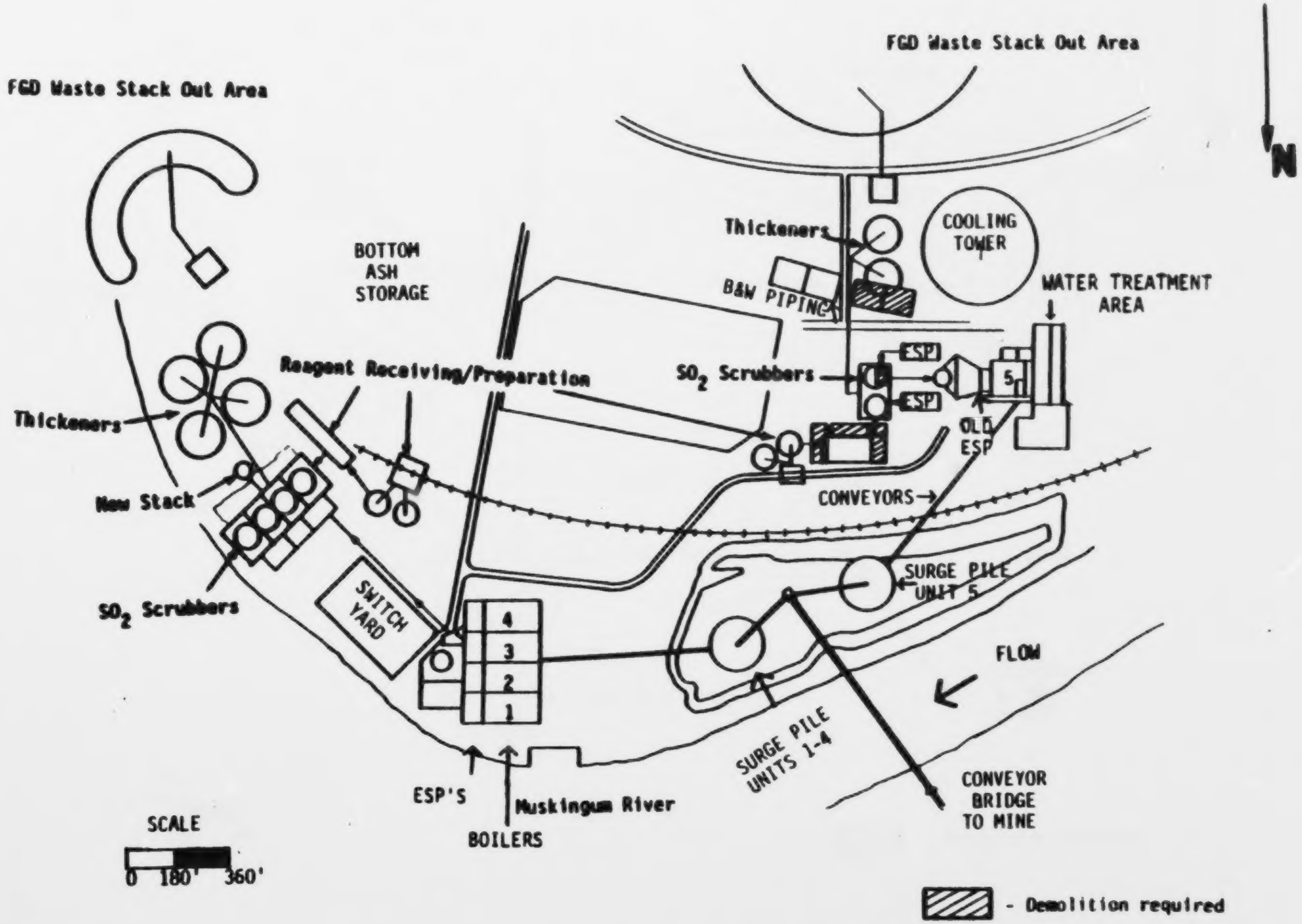

Figure 5-2. Muskingum River lime/limestone FGD equipment layout.

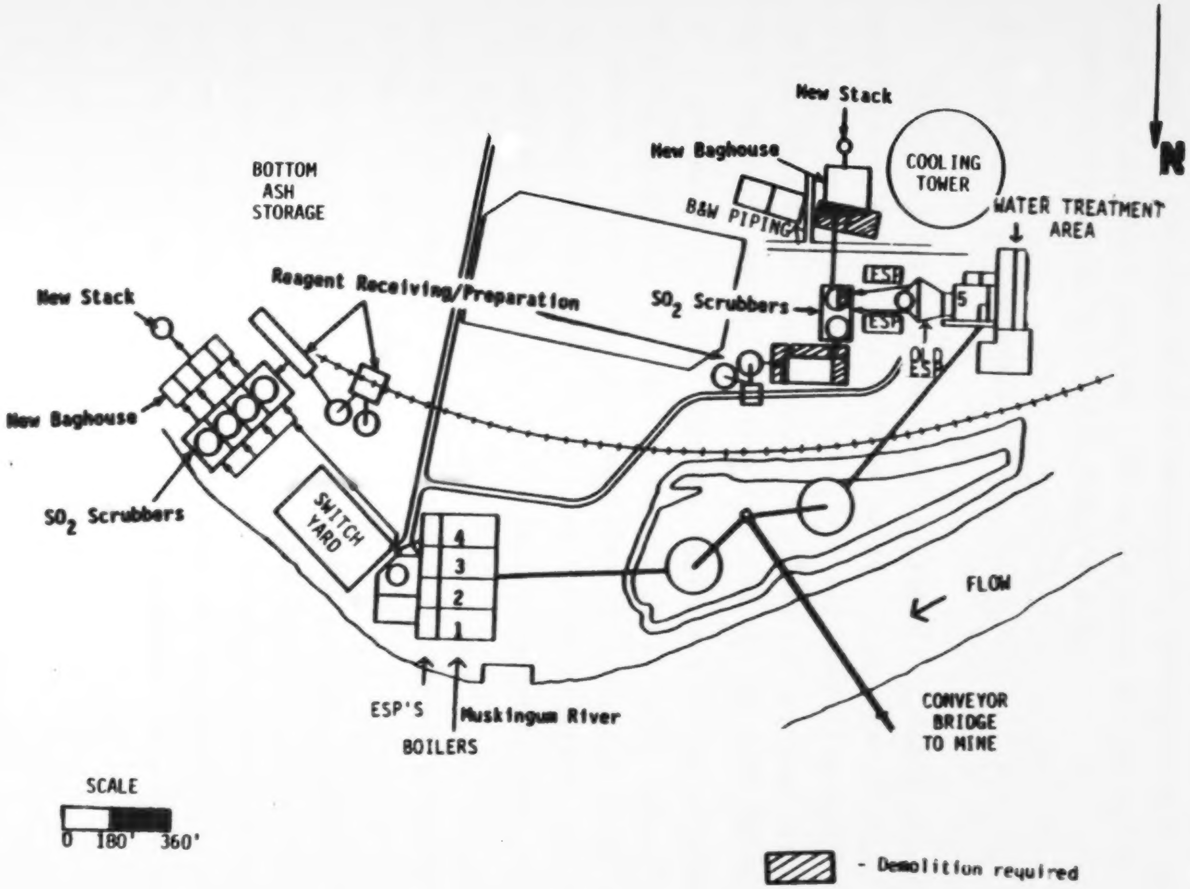

Figure 5-3. Muskingum River lime spray drying equipment layout.

on the backfilled sluice pond. For unit 5 the spray dryer vessels will be located behind the existing ESPs. Both reuse of the existing ESPs and chimney and installation of a new baghouse and new chimney adjacent to the cooling tower were examined. FGD waste would be disposed of in an off-site landfill assumed to be 5 miles from the plant.

5.2.1.3 Scope Adjustments--

Table 5-3 presents the scope adjustments included to adjust IAPCS model costs to reflect site-specific retrofit costs. For the cases where units 1 through 4 are scrubbed, the demolition and relocation of the large diameter bottom ash sluice lines, conversion of wet ash disposal system to dry ash handling, and a new chimney were included for the L/LS FGD case.

For the unit 1-4 LSD FGD case, conversion of the ash handling system from wet to dry is not required because the existing ESPs will be replaced by fabric filters. The additional cost for a new ash sluice pond to replace the bottom ash pond used for locating the FGD equipment for units 1-4 was included by increasing the general facilities percentage.

For unit 5 L/LS FGD, the cost conversion of a dry fly ash handling, boiler draft controls, and demolition of 3 warehouses (estimated to be 22,900 ft^2) were included.

For the unit 5 LSD FGD two scenarios are investigated. First, the existing ESP is reused and the fly ash disposal system is converted to dry handling. Second, a new baghouse and chimney is installed adjacent to the cooling tower. The cost of demolishing the concrete slabs, adjacent to the cooling tower, were accounted for in the general facilities cost.

5.2.1.4 Location and Retrofit Factors--

Tables 5-4, 5-5, and 5-6 summarize the retrofit factors used for all cases. Location factors adjust the control costs from the EPRI base case location to that of the Muskingum River plant. The seismic zone and climate

TABLE 5-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR MUSKINGUM RIVER PLANT

Scope Adjustment	Description[a]
• New chimney	A new chimney was added for all L/LS FGD and LSD-FGD cases on boilers 1-4 ($7.18/kW).
• Modify draft controls	Balanced draft controls were required for all FGD cases ($1.22/kW).
• Building demolition and relocation, duct work demo, and electrical Demolition	Demolition and relocation of 800 feet of large diameter bottom ash sluice lines for units 1-4 ($2.1/kW); demolition of 3 warehouses and 1 slurry pump house for unit 5 ($1.85/kW).
• Ash removal/conveyance modification	Conversion of wet disposal to dry ash handling for L/LS FGD cases and LS FGD with reuse ESP ($7.8-8.7/kW).

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

TABLE 5-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR MUSKINGUM RIVER PLANT

		Retrofit Factors									Retrofit Factors			
		Boiler #1-2				Boiler #3-4					Boiler #5			
Item	Units 1-4 LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	Unit 5 LOCF	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT														
Reagent Feed	1.13	1.01	1.05	1.00	1.06	1.01	1.05	1.00	1.06	1.09	1.13	1.15	1.00	1.30
SO_2 Removal	1.08	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10	1.07	1.06	1.30	1.00	1.38
Flue Gas Handling	1.09	1.03	1.50	1.80	2.78	1.03	1.50	1.70	2.63	1.09	1.06	1.30	1.15	1.58
Waste Handling	1.11	1.03	1.05	1.01	1.09	1.03	1.05	1.01	1.09	1.08	1.03	1.15	1.03	1.22
General Support Eqmt.	1.13	1.01	1.24	1.00	1.25	1.01	1.24	1.00	1.25	1.09	1.12	1.24	1.00	1.39
SCOPE ADJUSTMENTS														
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Chimney	1.11	1.00	1.06	1.00	1.06	1.00	1.06	1.00	1.06	N/A[f]	N/A	N/A	N/A	N/A
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES														
Engineering - %			11				11					13		
General Facilities - %			10				10					10		

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 5-7 for distance assumptions.
[e] AGGF = Aggregate Factor.
[f] N/A = Not applicable.

TABLE 5-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR MUSKINGUM RIVER PLANT

		Retrofit Factors									Retrofit Factors			
	Units 1-4	Boiler #1-2				Boiler #3-4				Unit 5	Boiler #5			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	LOCF	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT														
Reagent Feed	1.33	1.01	1.05	1.00	1.06	1.01	1.05	1.00	1.06	1.17	1.13	1.15	1.00	1.30
SO_2 Removal	1.16	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10	1.10	1.06	1.30	1.00	1.38
Flue Gas Handling	1.16	1.03	1.50	1.80	2.78	1.03	1.50	1.70	2.63	1.16	1.06	1.50	1.33	2.11[f]
General Support Eqmt.	1.30	1.01	1.24	1.00	1.25	1.01	1.24	1.00	1.25	1.16	1.12	1.24	1.00	1.39
SCOPE ADJUSTMENTS														
New Ash Silo System	N/A[g]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Chimney	1.11	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02	1.06	1.00	1.00	1.00	1.00
Baghouse	1.16	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10	1.06	1.06	1.30	1.00	1.38
ESP Plate Addition	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.06	1.30	1.00	1.38
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES														
Engineering - %			11				11					11		
General Facilities - %			10				10					10		

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 5-7 for distance assumptions used.
[e] AGGF = Aggregate Factor.
[f] Based on reusing ESP. If a new baghouse is used, the aggregate factor is 1.58.
[g] N/A = Not applicable.

TABLE 5-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES AT MUSKINGUM RIVER PLANT

	Units 1-4	Boiler #1-4				Unit 5	Boiler #5			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT										
Reagent Feed	1.13	1.01	1.05	1.00	1.06	1.09	1.13	1.15	1.00	1.30
SO_2 Removal	1.08	1.00	1.10	1.00	1.10	1.07	1.06	1.30	1.00	1.38
Flue Gas Handling	1.09	1.03	1.50	1.75	2.70	1.09	1.06	1.30	1.15	1.58
Waste Handling	1.11	1.03	1.05	1.01	1.09	1.08	1.03	1.15	1.03	1.22
General Support Equipment	1.13	1.01	1.24	1.00	1.25	1.09	1.12	1.24	1.00	1.39

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 5-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

factors were assumed to be 1.0 and the labor and materials factor used was 1.06. For all of the unit 5 FGD process areas, the soil condition factors for ground water at 3 feet were used to account for the poor load bearing capacity of the soil. For unit 1-4 cases, flood plain soil factors were used for all process areas located on the backfilled ash pond and the groundwater at 3 feet factor was used for flue gas handling.

Retrofit factors account for underground obstructions, site access and congestion, and distances to equipment. Since the majority of the FGD equipment for units 1-4 was located on the backfilled sluice pond, small underground factors were assigned. However, for the flue gas handling equipment a medium underground factor was used. For unit 5 a medium underground factor was used for SO_2 removal while the remaining FGD components were assigned a low factor.

For units 1-4, low access and congestion factors were assigned to all FGD components except general support equipment which was assigned a medium factor and flue gas handling which was assigned a high factor. For unit 5, all components were assigned medium factors reflecting the moderate site congestion around unit 5. Ductwork length and distances between process areas used in developing FGD retrofit factors are shown in table 5-7.

5.2.1.5 Overall Retrofit Factors and Costs--

Table 5-8 presents the overall retrofit factors and costs for all FGD cases. Figures 5-4 and 5-5 present the plant level costs versus SO_2 reduction associated with installing L/LS and LSD FGD. Applying L/LS FGD at Muskingum River would result in an estimated plant level reduction of 255,000 tons of SO_2 per year assuming a 90 percent level of reduction. Unit 5 is the most cost effective to control. Units 1, 2, 3, and 4 have higher unit costs than unit 5 because their sizes are significantly smaller and long flue gas duct runs would be required.

Figure 5-4 also shows the cost impact of the low capital cost L/LS FGD cases. The low cost control system approach reduces the annual cost of

TABLE 5-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR MUSKINGHAM RIVER PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
L/LS FGD				
Boilers 1-2	900	50	100	260
Boiler 3-4	800	50	100	260
Boiler 5	150	150	100	580
LSD FGD (reuse ESP)				
Boiler 5	150	325	100	N/A[c]
LSD FGD (new baghouse)				
Boilers 1-2	900	50	100	N/A
Boilers 3-4	800	50	100	N/A
Boiler 5	150	150	100	N/A

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not application for spray drying FGD.

TABLE 5-8. L/LS AND LSD FGD COSTS FOR MUSKINGUM RIVER PLANT (August 1987 Dollars)

		IAPCS Retrofit Costs[a]		
Case Description	Overall Retrofit Factor	Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boilers 1-2	1.70	311.7-357.5	671-762	22.8-25.9
Boilers 3-4	1.66	301.8-345.5	704-813	23.9-27.6
Boiler 5	1.54	202.9-237.7	496-573	16.9-19.5
LSD FGD (reuse ESP)				
Boiler 5	1.70[b]	160.0	501	11.0
LSD FGD (new baghouse)				
Boilers 1-2	2.01[c]	300.9	612-615	19.1
Boilers 3-4	1.96[c]	306.9	650-663	21.2-21.7
Boiler 5	2.10[c]	263.2	553	15.9
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1-4	1.68	157.6	383	13.0
Boiler 5	1.54	155.8	377	12.8

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] No plate area increase needed.

[c] Includes impact of new baghouse.

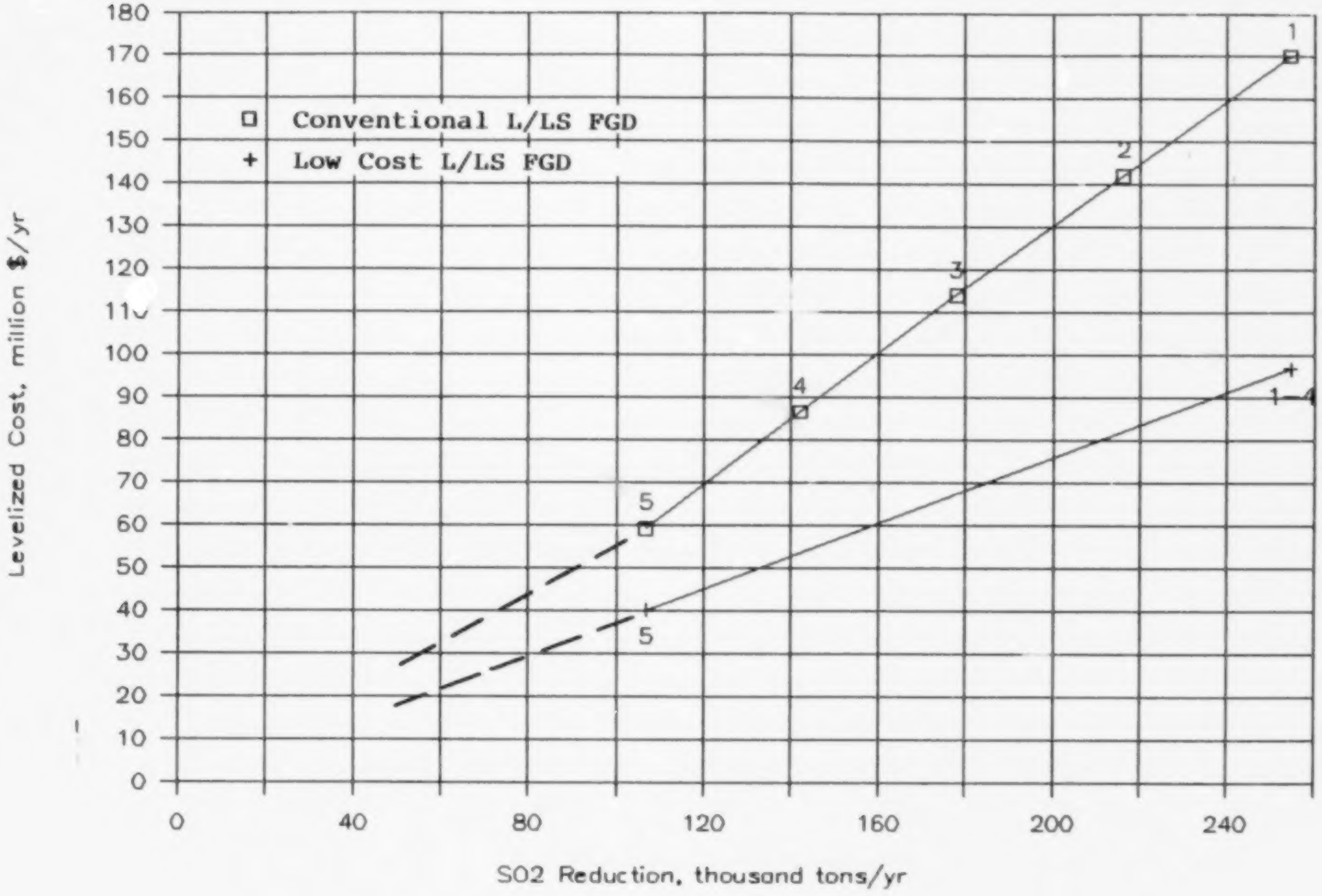

Figure 5-4. Muskingum River Plant L/LS cost versus SO_2 reduction.

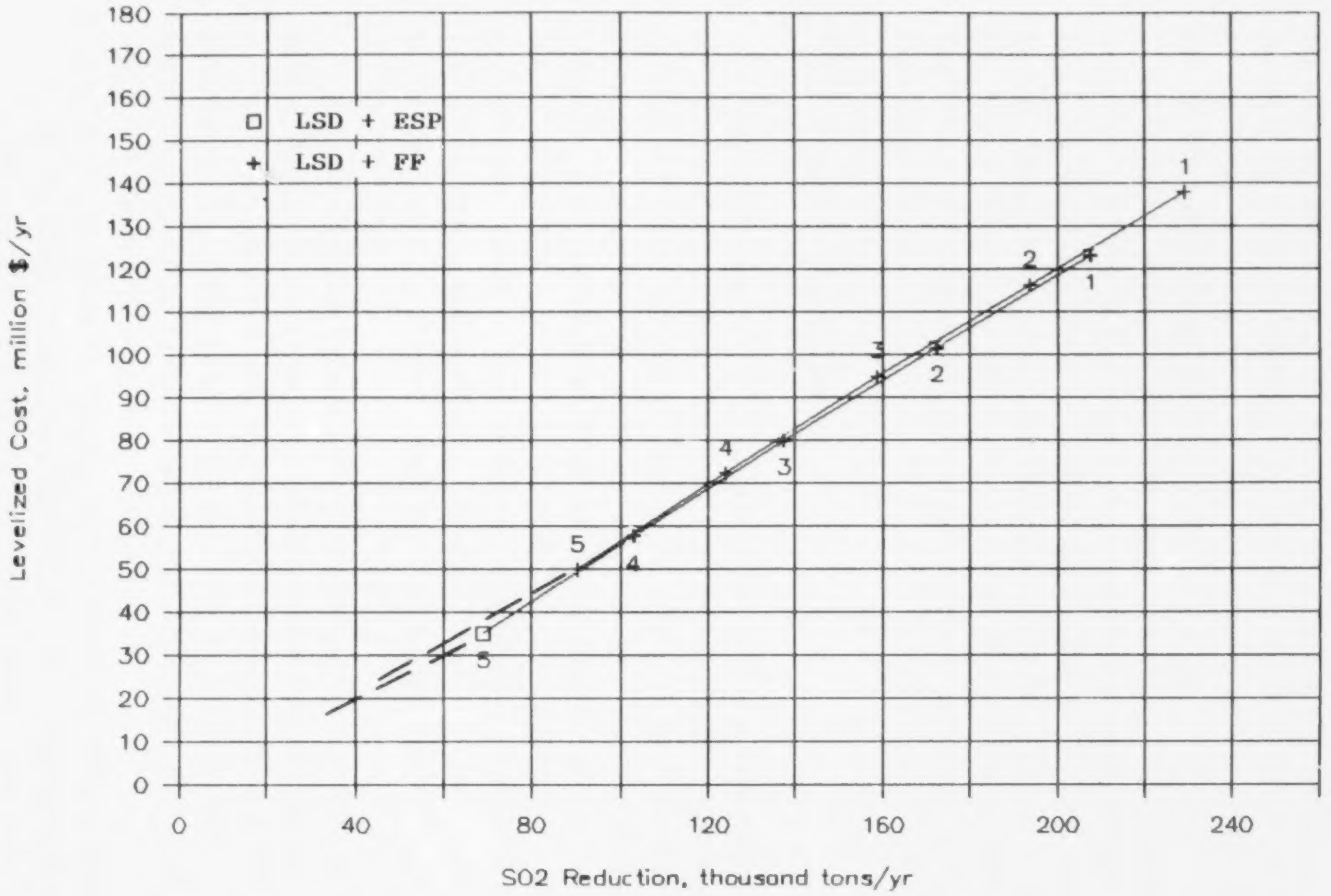

Figure 5-5. Muskingum River Plant lime spray dryer FGD cost versus SO_2 reduction.

control for units 1-4 by 48 percent and unit 5 by 30 percent. The larger decrease in costs for units 1-4 versus unit 5, is a result of the benefits of economies of scale for a 200 MW FGD system (individual boilers) versus an 800 MW FGD system (combined boilers).

Figure 5-5 presents the plant level cost for LSD FGD versus plant SO_2 reduction. If LSD FGD was applied to the boilers at Muskingum River, plant level SO_2 emissions would be reduced by 208,000 to 230,000 tons per year. As the figure shows, the lower reduction would be achieved with the use of new fabric filters for units 1-4 and reuse of the existing ESPs at unit 5. The larger reduction would be achieved with use of fabric filters on all five units.

5.2.2 Coal Switching/Blending

Coal switching was only evaluated for boiler 5 because boilers 1-4 are wet bottom type boilers. These boilers would require a low sulfur coal with special ash fusion properties making it difficult to estimate fuel price differentials and boiler derating cost impacts. Additionally, the necessary ESP plate area additions would be expensive due to the limited access near the existing ESPs. Table 5-9 presents the coal quality data used to evaluate the impact of coal switching on Muskingum River Unit 5. Because no coal ash analysis was available, the cost impacts of coal switching on pulverizer capacity, boiler slagging, fouling and tube erosion rate could not be evaluated.

ESP performance impacts were evaluated using the IAPCS model to determine the needed plate area. A comparison between the needed plate area and the existing plate area was made to determine the need for SO_3 conditioning or additional plate area, assuming SO_3 conditioning reduces necessary plate area by 25 percent. The IAPCS model estimated that unit 5 would require no ESP plate area increase.

The plant currently receives coal by conveyor from a nearby mine. As such, the Muskingum River plant has no coal receiving/storage/handling facilities adequate for handling low sulfur coals. The coals would have to be received by rail because the Muskingum River is not navigable by barge.

TABLE 5-9. CHARACTERISTICS OF EXISTING AND SWITCH COALS FOR MUSKINGUM RIVER PLANT

	Existing Coal	Switch Coal
Item	Boiler 5	Boiler 5
COAL PARAMETERS		
Percent sulfur	4.4	.89
Percent ash	12.4	16.6
Btu per pound	11,364	12,058
ESP PARAMETERS		
Existing/needed SCA[a]	424	260

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

Plant level cost for switching to a low sulfur coal at Muskingum River Unit 5 are presented in Table 5-10 for two fuel price differentials of $6.92/ton between the existing coal at $37.97/ton and an eastern Kentucky low sulfur coal at $44.89/ton and a fuel price differential of $15/ton over the 1985 fuel price differential. These costs do not include the impact of adding rail receiving facilities. Approximately 96,300 tons of SO_2 reduced per year would result from switching to a low sulfur coal at Muskingum River Unit 5.

TABLE 5-10. COAL SWITCHING COSTS FOR MUSKINGUM RIVER PLANT
(August 1987 Dollars)

		@ $6.92/ton FCD		@ $21.92/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
5	96,300	176	5.4	523	16.0

5.2.3 Physical Coal Cleaning

Physical coal cleaning was not examined at the Muskingum River plant because the coal is presently washed to reduce sulfur and ash prior to firing in the boilers. The wash plant was not visited by Radian personnel nor was any washability data available. Although additional sulfur removal could be economically removed by deeper coal cleaning, insufficient data was available to evaluate the cost/performance of advanced coal cleaning. However, it is likely that deep coal cleaning would be an attractive control technology versus coal switching for achieving moderate SO_2 reductions because boiler operating impacts at units 1-4 and capital costs for rail delivery by facilities and track would be avoided.

5.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost and performance estimates for the SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a higher degree of uncertainty due to the lack of commercial scale data. For the Muskingum River plant, the following control technologies were evaluated: furnace sorbent injection (FSI), duct spray drying (DSD), and repowering at boilers 1-4. The following discussion presents the retrofit issues and the cost/performance estimates.

5.3.1 Sorbent Injection Technologies

FSI and DSD technologies are in various stages of research and development for retrofit situations. Many costs of retrofit are built into the base case design and costs. Retrofit factors developed for these technologies have scope adders not included in developers' assumptions. These adders include demolition of existing ESPs, installation of fabric filters, and conversion of wet fly ash handling systems to dry handling/storage. Basic assumptions and cost adjustments made for FSI and DSD at Muskingum station are identified in table 5-11. Table 5-12 presents the estimated retrofit costs for FSI and DSD. A brief discussion follows describing how these factors and costs were determined for each technology.

5.3.1.1 Furnace Sorbent Injection--

Furnace sorbent injection was evaluated for all boilers. The sorbent was assumed to be a prepared calcitic hydrate material with the receiving/storage facilities located between the rail spur and plant south of units 1-4 and adjacent to the cooling tower for unit 5. These locations were chosen to provide access to railroad spurs and roads and to minimize solids conveying distances. Approximately 400 to 700 feet of sorbent conveying line would be required for boilers 1 through 4, respectively. For unit 5, approximately 600 feet of conveying line is necessary. The

TABLE 5-11. SCOPE ADJUSTMENTS FOR FSI AND DSD AT MUSKINGUM RIVER PLANT

Item	Boiler 1-2	Boiler 3-4	Boiler 5
BASIC ASSUMPTIONS			
Approximate access/congestion rank	Low	Low	Low
Can the existing ESP be upgraded?	No	No	Yes
Was a new baghouse evaluated for DSD?	Yes	Yes	No
Distance to final waste disposal (miles)	5	5	5
SCOPE ADDERS			
Install dry ash handling system for ESP reuse[a]	No	No	Yes
New Stack[b]	Yes	Yes	No
Additional duct work (ft)[b]	950	850	0
Duct demolition length (ft)	50	50	50
ADDER COSTS AND RETROFIT FACTOR SUMMARY			
Scope adder costs for new baghouse (10^3 \$)[c]	8,377	8,664	N/A[d]
Scope adder costs for ESP reuse (10^3 \$)[c]	N/A	N/A	4621
Baghouse retrofit difficulty factor	1.10	1.10	N/A
ESP upgrade retrofit difficulty factor (for plate area addition)	N/A	N/A	1.38

---

[a] Not applicable when a new baghouse is installed.

[b] Not applicable when the existing ESP is used.

[c] June 1985 dollars.

[d] N/A = Not applicable.

TABLE 5-12. RETROFIT COSTS FOR FSI AND DSD FOR MUSKINGUM RIVER PLANT
(August 1987 Dollars)

Case Description	IAPCS Capital Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50% removal)[a]				
Boiler 5	46.5	10.6	559	59,300
Furnace Injection (70% removal)[b]				
Boiler 5	40.6	9.6	364	83,100
Duct Spray Drying (ESP reuse)				
Boiler 5	49.7	6.0	407	46,000
Duct Spray Drying (new baghouse)				
Boiler 1	202.5	14.3	581	27,800
Boiler 2	202.5	14.4	583	27,700
Boiler 3	208.7	16.0	628	27,100
Boiler 4	208.7	16.3	640	26,400

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] The case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

additional solid waste storage silos were located adjacent to the sorbent preparation area to allow for recycle of spent sorbent if this option was desired. It was assumed that the alkaline waste material could be disposed of at an off-site landfill five miles from the plant.

Units 1 and 2 ESPs have SCAs of 202 and units 3 and 4 ESPs have SCAs of 192. These ESPs would not be able to remove the additional solids due to furnace sorbent injection even with flue gas humidification and tune-up. As a result, costs were not presented for these boilers because it is unlikely that the ESPs would be reused. Unit 5 ESP has an SCA of 424, and with humidification is large enough to handle the increased solids load. However, the ash handling and disposal system for unit 5 must be converted from wet to dry ash disposal.

5.3.1.2 Duct Spray Drying--

The lime receiving/storage/conveying systems would be in the same location for LSD FGD. The retrofit factors for access/congestion, underground obstructions, soil conditions and location factors would be small, within the scope of 65 percent process and project contingency factors used for this technology.

A major consideration associated with the performance of DSD is duct residence time. It is necessary to achieve sufficient duct residence time to obtain favorable SO_2 capture. Duct residence times for unit 5 would be sufficient but probably inadequate for units 1-4 if the existing ESPs are revised.

Another major process parameter impacting the performance of DSD is the flue gas temperature available for evaporation of the slurry. It was estimated by IAPCS that with sufficient duct residence time the SO_2 removal as a function of spray down temperature would be 44 percent at units 1 & 2, 48 percent at units 3 & 4, and 39 percent at unit 5 applying DSD with ESP upgrade. However, use of new fabric filters would give an estimated: 65 percent SO_2 reduction at units 1 & 2, 68 percent reduction at units 3 & 4, and 62 percent reduction at unit 5. IAPCS estimated that the unit 1-4 ESPs would need additional plate area in addition to tune-up for adequate particulate control. Because little space is available to expand the ESP

plate area at units 1-4, not enough duct residence time between the boilers and existing ESPs and very low SO_2 reduction would be obtained when reusing the ESPs, it was assumed new fabric filters would be necessary.
Because unit 5 has sufficient duct residence time available and the existing ESP is large enough for adequate particulate control, DSD with ESP reuse was evaluated.

5.3.1.3 Overall Retrofit Factors and Costs--

Table 5-12 presents the estimated retrofit costs for FSI and DSD. Figure 5-6 shows the costs of retrofitting FSI and DSD versus the plant level SO_2 reductions achieved. For FSI technology, two cost/performance estimates were generated to present the range of anticipated SO_2 removal (50 and 70 percent) and sorbent utilization (25 and 35 percent) potential. If 50 percent removal is achieved at unit 5, an overall reduction of 59,300 tons per year of SO_2 would result. If 70 percent removal is achieved, the resulting SO_2 reduction would be 83,100 tons per year. Applying DSD to all boilers would result in an annual reduction of 155,000 tons per year of SO_2.

5.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

Boilers 1-4 are small (205-215 MW) and have been in service for 29 to 34 years. As such, these boilers are potential candidates for FBC/CG retrofit. Currently these boilers are base loaded units (capacity factor > 50 percent) and have good heat rates (<10,000 Btu/net kWh). These factors would suggest that the boilers are not near term candidates for FBC/CG retrofit. However, because retrofit of an FGD system would be moderately difficult and coal switching could result in significant unit derates, FBC/CG retrofit could be attractive if a high level of SO_2 reduction were required at these units.

5.4 NO_x CONTROL TECHNOLOGIES

This section presents the cost and performance estimates developed for NO_x controls. Control applicability and performance are discussed in the

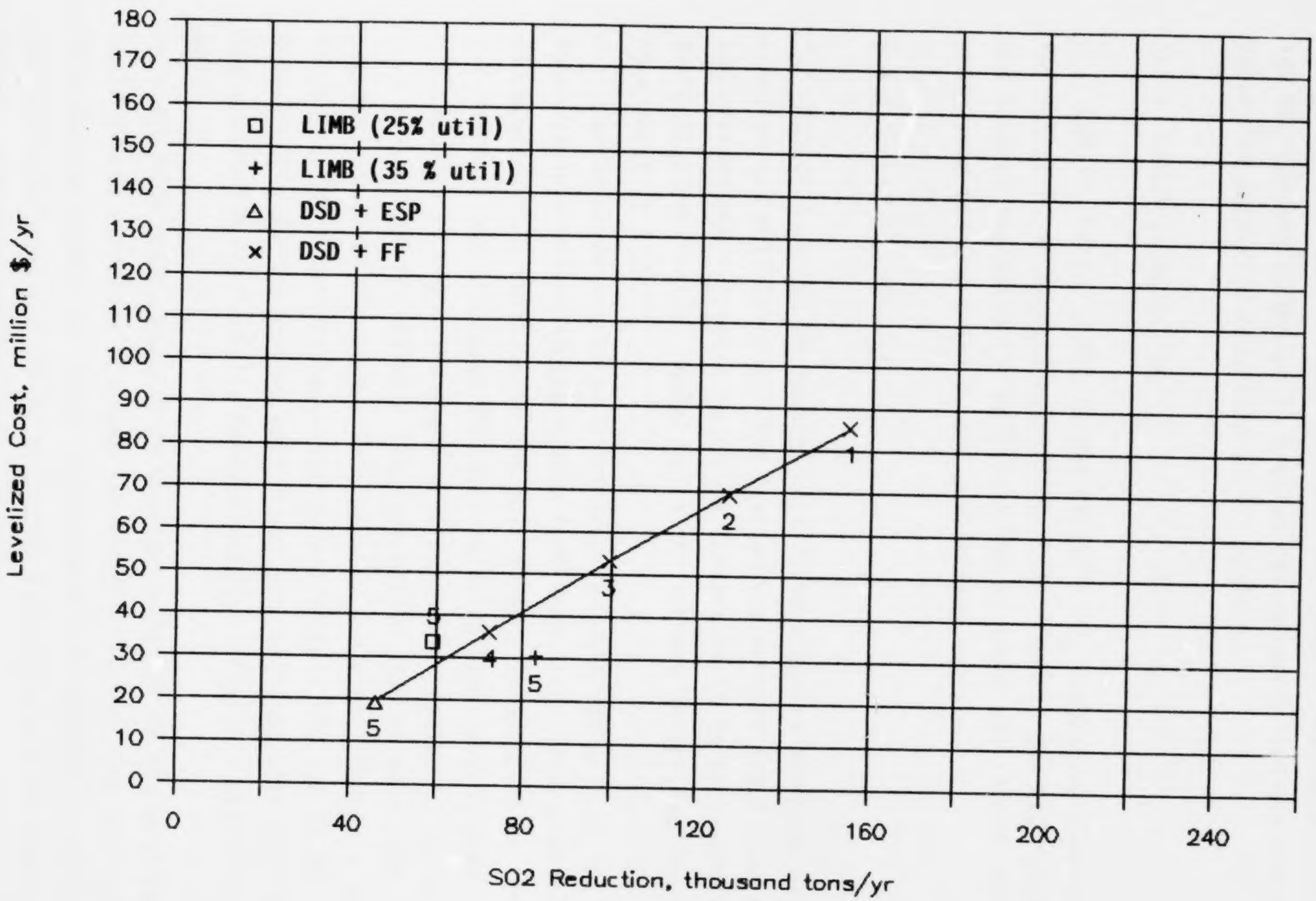

Figure 5-6. Muskingum River Plant FSI/DSD cost versus SO_2 reduction.

following sections for each boiler. The controls evaluated are as follows: low NO_x burners at boiler 5, natural gas reburn at boilers 1-4, and selective catalytic reduction at all boilers.

5.4.1 Low NO_x Combustion

Low NO_x burner (LNB) is the retrofit NO_x combustion control considered for boiler 5, an opposed wall-fired unit. Natural gas reburning (NGR) is the control evaluated for boilers 1 and 2, front wall-fired, wet bottom units, and boilers 3 and 4, cyclone furnace units.

5.4.1.1 Low NO_x Burners--

Boiler 5, a 585 MW opposed wall-fired unit, is equipped with both circular and cell burners. The average burner heat input (approximately 105 million Btu/hr) relative to the furnace depth is intermediate to high for cell burner units. Relative to the furnace height the average burner heat input is high.

Carbon burnout must be considered in a LNB retrofit at boiler 5. The nonvolatile fraction of the boiler heat input flux (approximately 430 Btu/sec-ft^2) relative to the bulk furnace residence time (approximately 1.7 seconds) and the upper furnace residence time (approximately 1.7 seconds) is high--the highest of any boiler evaluated in the Ohio study.

For thermal NO_x effects, the volumetric heat release rate (approximately 24,000 Btu/hr-ft^3) is high for a cell burner unit. However, the burner zone heat release rate (approximately 550,000 Btu/hr-ft^2) is intermediate for an opposed wall-fired unit equipped with cell burners and the vertical burner spacing (approximately 14 feet) is wide for this type of unit.

The high-sulfur content (4.4 weight-percent) of the coal potentially could create corrosion problems for a LNB retrofit. The coal is fired at an intermediate excess air level (approximately 20 percent). Furnace slagging was indicated, and the steam generation rate/furnace plan area slagging factor (1,800 lb/hr-ft^2) verifies this.

Based on these considerations, the NO_x reduction performance of a LNB retrofit for Muskingum River boiler 5 is estimated to be low to intermediate (20 to 30 percent). This is due to the relatively shallow furnace depth, potential carbon burnout problems, high volumetric heat base rate, and slagging characteristics of the existing unit's operation. These factors are ameliorated somewhat by the wide spacing between burner elevations. The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls at the six Muskingum Plan boilers are summarized in table 5-1.

5.4.1.2 Natural Gas Reburning--

Natural gas reburning (NGR) was assumed to be applicable to boilers 1-4. A maximum NO_x emission reduction of 50 percent was estimated to be achievable with injection of 15 percent of the boiler heat input as natural gas. The natural gas and overfire air would be injected in the upper furnace section. Since the upper furnace residence time in boilers 3 and 4 is low, a low to moderate NO_x reduction performance could be achieved with NGR retrofit. Boilers 1 and 2 have intermediate residence times, and performance should not be limited significantly.

5.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700°F for coal-fired systems requires the SCR system to be located between the economizer and air heater or the use of a flue gas reheater to be used with a tail-end SCR system.

For units 1-4, installation of the reactors between the economizers and existing air heater would require the reactor to be built on a support structure above the boiler building. Installation of the reactors after the economizer for unit 5 would require the original ESP to be demolished. The catalytic reactor system would be constructed in its place, where the access and congestion retrofit factors would be very high. For all units, downtimes would be extensive making it necessary to purchase power to replace the base load generating capacity of this plant. As such, a tail-end SCR system was selected for evaluation.

Table 5-13 summarizes the key information used to develop the SCR unit retrofit difficulty and scope adjustments. The new flue gas duct lengths are for ducting the flue gases from the ESP outlet to the catalytic reactor and back to the chimney. The heat exchanger costs are for the catalytic reactor and preheater to raise the flue gas temperature up to 650-700^{0}F and to recover this heat from the flue gas leaving the reactors. The general facilities cost account for new roads and soil conditions.

5.4.3 Summary of NO_x Control Costs

Table 5-14 and figure 5-7 present the annual cost of applying LNB at boiler 5 and natural gas reburning at boilers 1-4. The curve assumes a 30% NO_x reduction at boiler 5 and a 50 percent reduction at boilers 1-4. Application of LNC/NGR combination at the Muskingum Plant was estimated to reduce NO_x emissions by 21,300 tons per year at a unit cost of $203 and $1147 per ton of NO_x removed from boilers 5 and 1-4, respectively. Application of SCR to all boilers at Muskingham River, would reduce NO_x emissions by 38,700 tons per year at a unit cost of $2,352 to $3,302 per ton of NO_x removed.

TABLE 5-13. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR MUSKINGUM RIVER PLANT
(August 1987 Dollars)

	Boiler				
	1	2	3	4	5
Site access and congestion for SCR reactor	High	High	High	High	Low
SCOPE ADDER PARAMETERS					
Building demolition (1,000$)	0	0	0	0	0
Ductwork demolition (1,000$)	46	46	48	48	102
New duct length (feet)	100	100	500	100	250
New duct costs (1,000$)	754	754	3,877	775	3,482
New heat exchanger (1,000$)	2,867	2,867	2,950	2,950	5,379
Total scope adder costs (1,000$)	3,668	3,668	6,875	3,774	8,962
Retrofit factor for SCR	1.52	1.52	1.52	1.52	1.16
General facilities (percent)	13	13	17	17	13

TABLE 5-14. NO_X COST RESULTS FOR THE MUSKINGUM RIVER PLANT
(August 1987 Dollars)

NO_x Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_x Reduced (tons/year)
Low NO_x Burner	5	30	7.5	203	0.3	4,400
Natural Gas Reburn	1	50	16.1	1,237	4.6	4,200
	2	50	16.1	1,237	4.6	4,200
	3	50	15.9	1,147	4.7	4,300
	4	50	15.9	1,150	4.7	4,200
Selective Catalytic Reduction	1	80	155.1	2,352	14.1	6,800
	2	80	155.1	2,363	14.1	6,700
	3	80	170.1	2,585	16.8	6,900
	4	80	155.4	2,567	16.7	6,700
	5	80	101.0	3,302	12.2	11,600

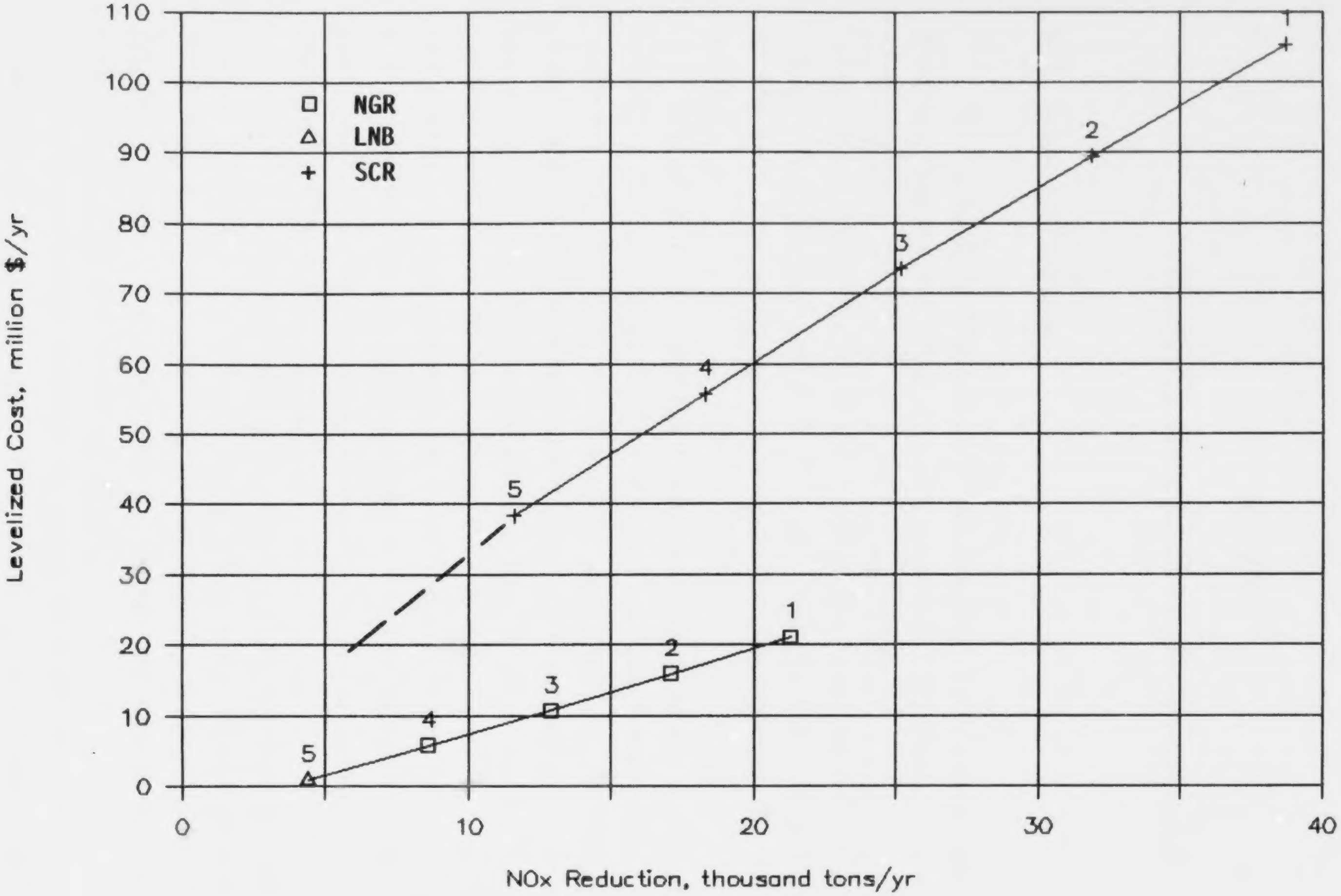

Figure 5-7. Muskingum River Plant NO_x control costs versus NO_x reduction.

SECTION 6

CONESVILLE PLANT RETROFIT FACTORS AND COSTS

6.1 PLANT DESCRIPTION

The Conesville Plant, owned and operated by Columbus and Southern Ohio Electric Company, is located in east-central Ohio about five miles southwest of Coshocton. The plant is totally coal-fired with a total net generating capacity of 1,885 MW. Figure 6-1 shows the location of the six boilers, control systems, and other facilities. The plant is bounded on the southwest by the Muskingum River, and rolling hills characterize the surrounding terrain.

Boiler units 1-6 and their accompanying turbines are located side-by-side in a straight line running southwest-northeast. Unit 1, at the southwest end of the line, is located approximately 350 feet northeast of the river. Warehouse and maintenance shops are located across a service road approximately 100 feet to the northwest of units 1 and 2. Coal storage is located in the area to the northwest of units 3-6 and behind the warehouse and shops. To the southeast of units 1-4 are electrical substations for the plant. Water treatment and cooling is located to the southeast of units 5-6. Handling facilities for coal, lime, and solid wastes occupy the area northeast of unit 6.

Units 1-3 are equipped with retrofit ESPs for particulate control. The ESPs on Units 4-6 are part of the original plant design as are the scrubbers on Units 5-6. Also, units 5-6 are equipped with overfire air ports for NO_x control. Table 6-1 presents the key design and operational data obtained from EIA Form 767 and the plant visit.

The plant mainly operates as a cycling plant to meet daily and seasonal fluctuations in system electricity demand. The minimum sustainable load for each unit is approximately 50 percent of the design capacity; below this level the unit is shut down. The capacity factors for units 5 and 6 have

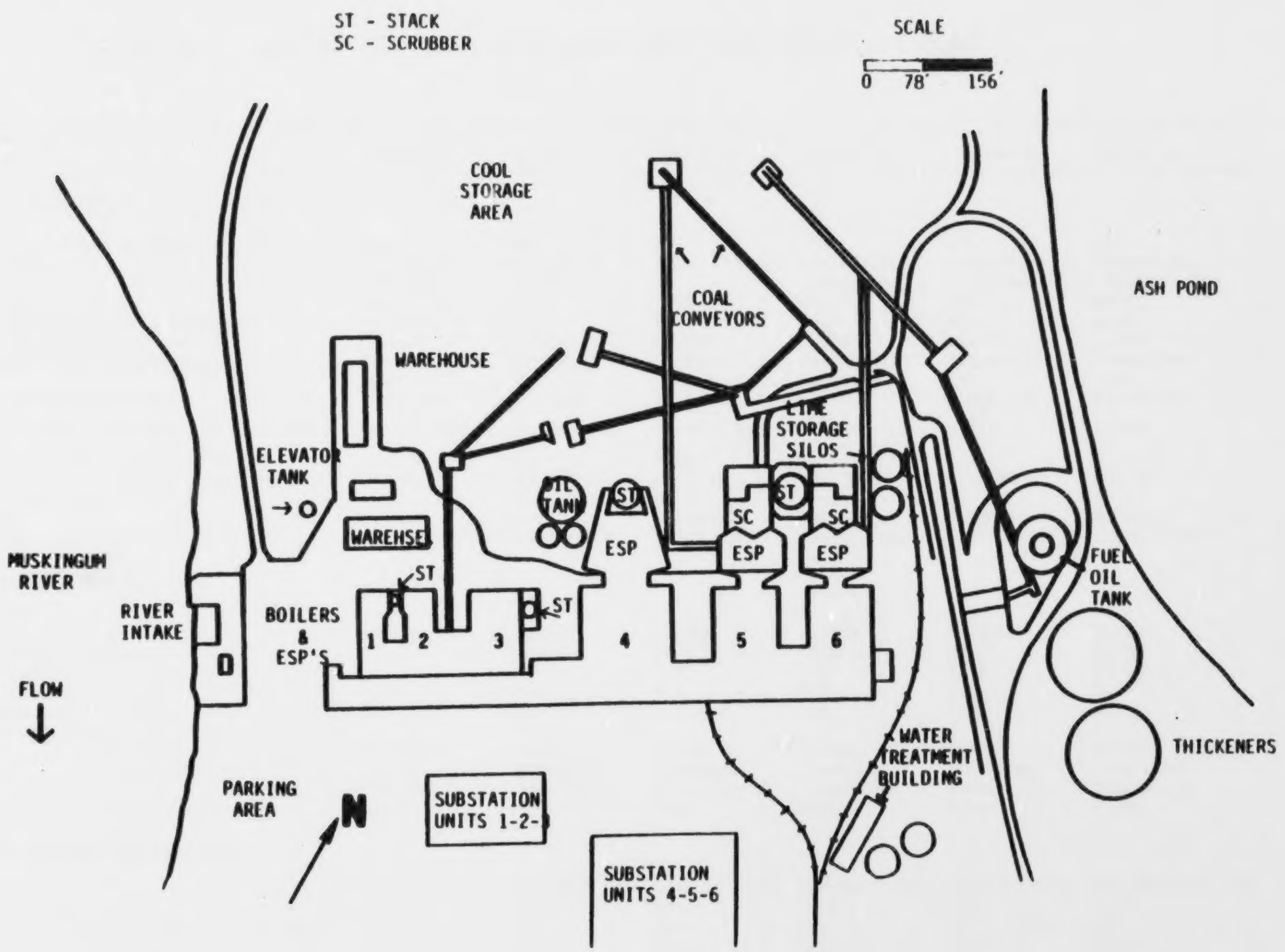

Figure 6-1. Conesville Plant plot plan.

TABLE 6-1. KEY DESIGN AND OPERATIONAL DATA FOR CONESVILLE PLANT

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5	Boiler 6
BOILER AND STACK DATA						
Net generating capacity (MW)	125	125	165	720	375	375
Boiler manufacturer	Babcock & Wilcox	Babcock & Wilcox	Riley Stocker	Combustion Engineering	Combustion Engineering	Combustion Engineering
Installation date	1959	1957	1962	1973	1976	1978
Capacity factor (10 year projected)	17.0	24.5	37.3	54.6	46.0	42.8
Heat rate (Btu/kW-hr)	11,100	13,600	10,690	9,950	11,100	11,466
Boiler type/firing type/bottom type	Cyclone/ wet	Cyclone/ wet	Front wall/ dry	Tangential/ (split)/dry	Tangential/ dry	Tangential/ dry
Boiler dimensions, (ft, D x W x H^{a})	27x15x50	27x15x50	25x47x60	51x110x177	51x60x149	51x60x149
Burner type/number of burners (# EL x #/EL)	Cyclone/2x2	Cyclone/2x2	Circular/2x2	--^{d}6x8	--^{d}5x4	--^{d}5x4
Burner spacing (vert x horiz, ft)	14x--^{b}	14x--^{b}	8.5x--^{b}	6x--^{b}	7.5x--^{b}	7.5x--^{b}
Burner zone heat release rate (Btu/hr-ft^{2})	533,000	533,000	305,000	194,000	203,000	203,000
Excess air (percent)	11	11	22	25	25	25
Draft type	Forced	Forced	Balanced	Forced	Balanced	Balanced
Flue gas flow rate (1000 acfm @ °F)	622 @ 288°F	622 @ 288°F	751 @ 288°F	2,620 @ 300°F	1,407 @ 300°F	1,407 @ 300°F
FUEL AND SORBENT DATA						
Coal quality^{c}						
Heat content (Btu/lb)	12,290	12,240	12,260	11,870	11,240	11,190
Volatile matter (percent)	29.2	29.3	29.2	28.8	27.7	27.6
Ash (percent)	7.7	7.5	7.7	9.1	12.3	12.4
Moisture (percent)	8.6	8.9	8.9	8.7	8.7	8.8
Sulfur (percent)	2.9	3.0	2.5	3.5	4.2	4.2
Coal delivery methods						
Current	Truck/ conveyor	Truck/ conveyor	Truck/ conveyor	Truck/ conveyor	Truck/ conveyor	Truck/ conveyor
Design	Truck/rail	Truck/rail	Truck/rail	Truck/rail	Truck/rail	Truck/rail
Likely method for sorbent delivery	Truck	Truck	Truck	Truck	Truck	Truck
PARTICULATE CONTROL EQUIPMENT DATA						
Type of control	ESP/cold side	ESP/cold side	ESP/cold side	ESP/cold side	ESP/cold side	ESP,FGD/cold side
New/retrofit installation	1976	1976	1977	1973	1976	1978
ESP specific collection area (ft^{2}/10^{3} acfm)	333	333	306	181	301	301
Total plate area (10^{3} ft^{2})	207.4	207.4	229.7	472.3	423.4	423.4
Emission standards (lb/10^{6} Btu)	0.1	0.1	0.1	0.1	0.1	0.1
ESP outlet emissions (lb/10^{6} Btu)^{d}	.02	.04	.05	.08	.06	.06
Design coal sulfur (percent)	4.4	4.4	4.4	4.4	4.4	4.4
Gas conditioning	None	None	None	Yes	None	None
Tested efficiency/design efficiency	--^{b}/99.7	--^{b}/99.7	--^{b}/99.7	--^{b}/99.3	--^{b}/99.7	--^{b}/99.7

(Continued)

TABLE 6-1. (CONTINUED)

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5	Boiler 6
NITROGEN OXIDE CONTROL EQUIPMENT DATA						
NO_x control equipment	None	None	None	OFA	OFA	OFA
Installation date				--[b]	1976	--[b]
SULFUR DIOXIDE CONTROL EQUIPMENT DATA						
SO_2 control equipment	None	None	None	None	FGD	FGD
Installation date					1977	1977
SOLID WASTE DISPOSAL DATA						
Ash transport system type						
Boiler bottom ash	Wet	Wet	Wet	Wet	Wet	Wet
Fly ash	Wet	Wet	Wet	Wet	Dry	Dry
Ash disposal method	On-site pond	On-site pond	On-site pond	On-site pond	Truck/ off-site	Truck/ off-site
Existing landfill capacity	9 years	9 years	9 years	9 years	9 years	9 years
Estimated distance to off-site disposal	3 miles	3 miles	3 miles	3 miles	3 miles	3 miles

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

decreased since January 1986 due to increased costs for off-site FGD waste disposal.

In addition to the generating units, large areas of the plant property are required for storage of washed and unwashed coal, electrical substation and transmission facilities, water treatment and cooling, and solid waste management. Units 1-3 use river water for once-through cooling. Units 4-6 use forced-draft cooling.

Coal supply for the plant is received by truck and conveyor, although railroad transport is a viable option. Trucked coal from nearby independent mines represents approximately 30 percent of the plant's total coal supply and is used entirely in scrubber-equipped units 5 and 6. Conveyor coal is received from a C&SO-owned wash plant located approximately 3 miles southeast. Units 1-4 burn a 2.9 percent sulfur coal, while units 5-6 burn a 4.2 percent sulfur coal from local areas in Ohio and West Virginia.

Fly ash from units 1-4 is wet sluiced to an on-site pond located along the plant's northeast boundary. Fly ash from units 5-6 is pneumatically conveyed to silos and is used for mixing with scrubber sludge. The stabilized sludge is temporarily stored on-site prior to being trucked to in an off-site landfill located three miles east of the plant.

6.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Conesville include lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, and coal switching. The following discussion presents the retrofit issues and cost/performance estimates developed.

6.2.1 Lime/Limestone and Lime Spray Drying FGD

6.2.1.1 Control Cases Evaluated--

Table 6-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. Retrofit factors and costs were developed for L/LS FGD and LSD FGD for units 1

TABLE 6-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR CONESVILLE PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (Wt %)	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	2.9	7,100
Boiler 2	90	2.9	8,100
Boiler 3	90	2.9	10,900
Boiler 4	90	2.9	74,500
LSD FGD (reuse ESP)			
Boiler 1	76	2.9	6,100
Boiler 2	76	2.9	6,800
Boiler 3	76	2.9	9,300
LSD FGD (new baghouse)			
Boiler 1	86	2.9	6,900
Boiler 2	86	2.9	7,800
Boiler 3	86	2.9	10,500
Boiler 4	86	2.9	71,600
LOW COST CONTROLS			
L/LS FGD			
Boilers 1-4	90	2.9	100,500

through 4. Units 5 and 6 presently have wet scrubbers in operation; thus L/LS and LSD FGD were not considered for these units.

Lime spray drying FGD for units 1 through 3 was examined under two scenarios. In the first case, it was assumed that the existing ESP was adequate to handle the additional solid loading. The second scenario assumed that a new baghouse would be installed to remove the particulate matter and FGD solids. For unit 4, it was assumed that the existing ESP would be inadequate to handle the increased solids loading and thus a new baghouse would need to be installed for LSD FGD.

6.2.1.2 Layout of Equipment and Design Basis--

Figures 6-2 and 6-3 show the general layout and location of the L/LS and LSD FGD control equipment. Scrubbers for all units can be located directly behind the existing stacks. In order to scrub unit 4, however, the coal stack out and conveying system must be rearranged. Also, the on-site coal storage capacity could be reduced. Lime could be brought in by truck as currently is done for units 5 and 6. The FGD waste would be stored temporarily on-site before being trucked later to an existing off-site landfill three miles from the plant.

6.2.1.3 Scope Adjustments--

Table 6-3 summarizes the cost adders that need to be included to adjust IAPCS costs to reflect site specific issues. For the cases where units 1, 2 and 3 are scrubbed, the following scope adjustments are necessary:

- demolition of 1,500 ft^2 storage building behind units 1 and 2,
- demolition of 12,100 ft^2 warehouse behind units 1 and 2,
- demolition of additional 9,900 ft^2 of warehouse and 3,300 ft^2 construction office for LSD FGD case where a new baghouse is required (this cost to be divided among units 1-2 and unit 3),
- boiler draft controls,
- chimney liner for L/LS FGD cases,

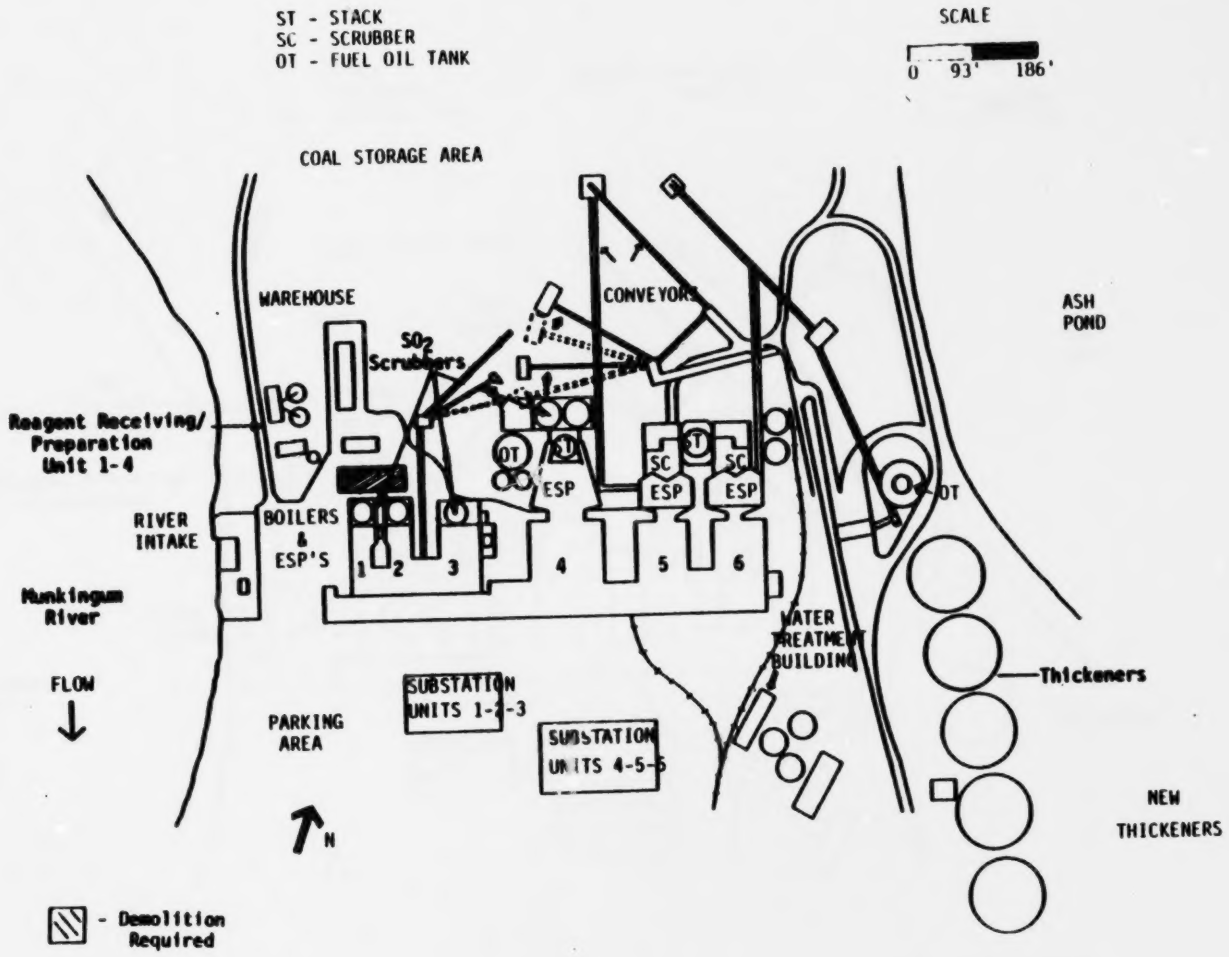

Figure 6-2. Conesville Plant lime/limestone FGD equipment layout.

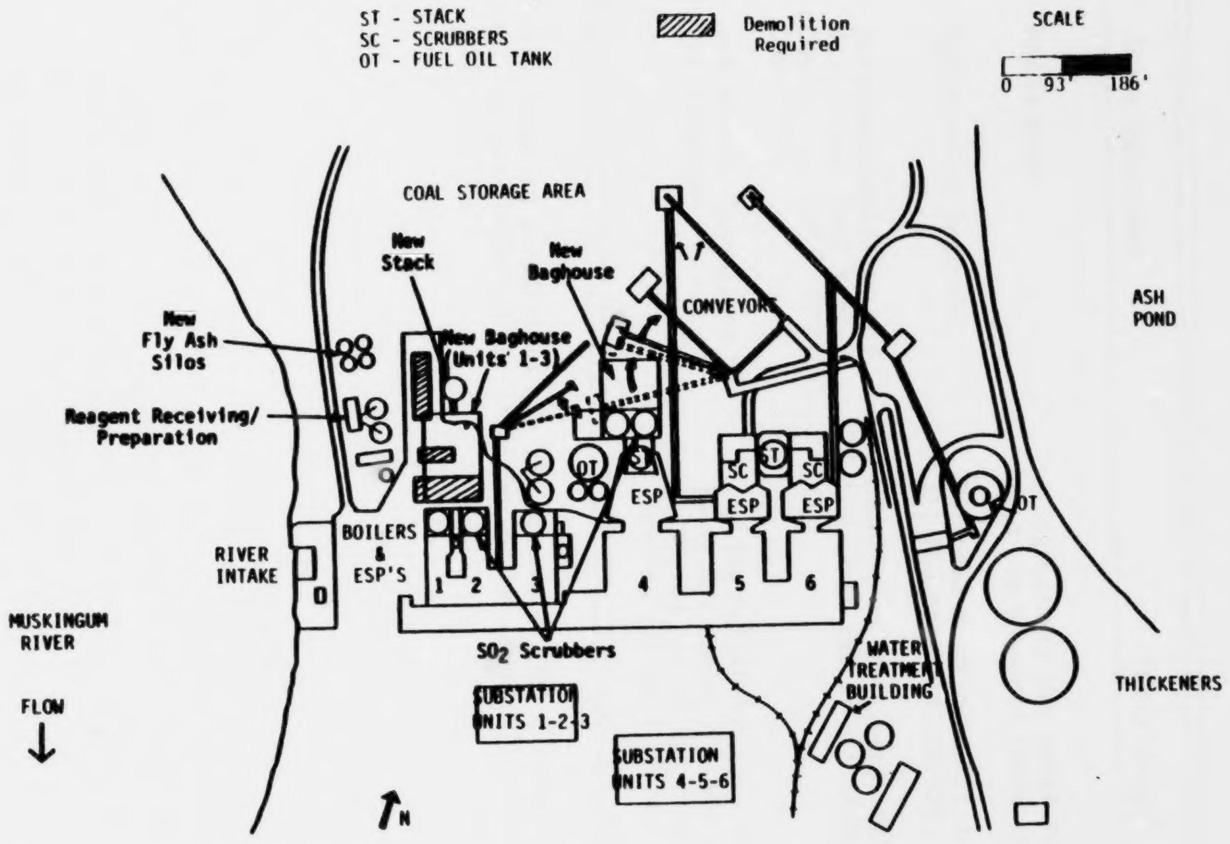

Figure 6-3. Conesville Plant lime spray drying FGD equipment layout.

TABLE 6-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR CONESVILLE PLANT

Scope Adjustment	Description[a]
• New Chimney	A new chimney was added for all LSD FGD with new baghouse cases ($7.18/kW).
• Modify Draft Controls	Balanced draft controls are required for all FGD cases ($1.20/kW).
• Building Demolition and Relocation, Duct Work Demolition, and Electrical Demolition	Demolition costs were included for all FGD cases ($0.17 - 5.64/kW).
• Ash Removal/Conveyance Modification	For the boiler 1-4 L/LS FGD and LSD FGD reuse ESP cases, the wet fly ash conveying system was converted to dry handling ($7.64-9.16/kW).

[a] Costs shown in parentheses are base costs in 1985 dollars. These costs have not been adjusted for location, process, retrofit, or other considerations.

- new chimney for LSD new baghouse cases and return ductwork to existing chimney for LSD reuse ESP cases, and
- convert fly ash handling from wet to dry for L/LS FGD and LSD reuse ESP cases.

In order to retrofit FGD on unit 4 the following modifications/additions are required:

- boiler draft controls,
- chimney liner for L/LS FGD cases,
- new chimney for LSD case,
- new particulate control for LSD case, and
- rearrangement of coal stack out equipment.

The expenses associated with rearranging the coal handling equipment and replacement of storage buildings and warehouses were accounted for by increasing the general facilities cost from 5 to 15 percent.

6.2.1.4 Location and Retrofit Factors--

Tables 6-4 through 6-6 summarize the location and retrofit factors for L/LS and LSD FGD. The aggregate location factor presented in the column titled LOCF incorporates the following: seismic zone factor of 1.0, climate zone factor of 1.0, and labor productivity and materials factor of 1.06. The soil condition factor was assumed to be base case of 1.0.

Retrofit factors account for site-specific conditions such as underground obstructions, site access and congestion, and distances to control equipment. A medium underground factor was applied to all process areas except waste handling which was assigned a small factor.

For all four units the scrubbers are located directly behind the existing stacks. Access and congestion is moderately difficult for SO_2 removal, flue gas handling, and general support equipment. The waste handling and reagent preparation equipment for units 1-4 are fairly accessible and thus a low congestion factor was used.

Ductwork tie-in distances and distances between process areas are presented in table 6-7. For the low cost case, the absorbers for each unit

TABLE 6-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR CONESVILLE PLANT

Item	All Units	RETROFIT FACTORS							
		Boiler #1-2				Boiler #3-4			
	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.06	1.06	1.05	1.00	1.11	1.06	1.05	1.01	1.13
SO_2 Removal	1.06	1.03	1.30	1.00	1.34	1.03	1.30	1.00	1.34
Flue Gas Handling	1.06	1.03	1.30	1.00	1.34	1.03	1.30	1.00	1.34
Waste Handling	1.06	1.03	1.05	1.16	1.26	1.03	1.05	1.15-1.16	1.24-1.26
General Support Equipment	1.06	1.06	1.24	1.00	1.31	1.06	1.24	1.00	1.31
SCOPE ADJUSTMENTS									
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Chimney	N/A[f]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %				12				12	
General Facilities - %				15				15	

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 6-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

[f] N/A = Not applicable.

TABLE 6-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR CONESVILLE PLANT

		RETROFIT FACTORS							
		Boiler #1-3				Boiler #4			
Item	All Units LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.06	1.06	1.05	1.00	1.11-1.13	1.06	1.05	1.02	1.13
SO_2 Removal	1.06	1.03	1.30	1.00	1.34	1.03	1.30	1.00	1.34
Flue Gas Handling	1.06	1.03	1.50	1.08	1.66[f]	1.03	1.30	1.00	1.34
General Support Equipment	1.06	1.06	1.24	1.00	1.31	1.06	1.24	1.00	1.31
SCOPE ADJUSTMENTS									
New Ash Silo System	1.06	1.00	1.00	1.00	1.00	N/A[g]	N/A	N/A	N/A
New Chimney[h]	1.06	1.00	1.02	1.00	1.02	1.00	1.02	1.00	1.02
Baghouse	1.06	1.03	1.30	1.00	1.34	1.03	1.30	1.00	1.34
ESP Plate Addition	1.06	1.03	1.50	1.00	1.55	N/A	N/A	N/A	N/A
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			12				12		
General Facilities - %			15				15		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 6-7 for distance assumptions used.

[e] AGGF = Aggregate Factor.

[f] Based on reusing ESP. If a new baghouse is used, the aggregate factor is 1.34 for units 1-2 and 1.48 for unit 3.

[g] N/A = Not applicable.

[h] For LSD with a new baghouse case.

TABLE 6-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES EVALUATED FOR CONESVILLE PLANT

		RETROFIT FACTORS			
	All Units	Boiler #1-4			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.06	1.06	1.05	1.01	1.13
SO_2 Removal	1.06	1.03	1.30	1.00	1.34
Flue Gas Handling	1.06	1.03	1.30	1.00	1.34
Waste Handling	1.06	1.03	1.05	1.16	1.26
General Support Equipment	1.06	1.06	1.24	1.00	1.31

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 6-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 6-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR CONESVILLE PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
L/LS FGD				
Boiler 1	75	75	100	2,400
Boiler 2	75	75	100	2,400
Boiler 3	75	75	300	2,200
Boiler 4	75	75	375	2,400
LSD FGD (new baghouse)				
Boiler 1	75	75	100	N/A[c]
Boiler 2	75	75	100	N/A
Boiler 3	180	75	300	N/A
Boiler 4	75	75	375	N/A
LSD FGD (reuse ESP)				
Boiler 1	75	150	100	N/A
Boiler 2	75	150	100	N/A
Boiler 3	75	150	300	N/A

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

would be located in the same place as for the individual unit cases. However, all other processing areas would be combined and would be located in the area behind units 1-3.

6.2.1.5 Overall Retrofit Factors and Costs--

Table 6-8 summarizes the retrofit costs and factors for L/LS and LSD FGD. Figures 6-4 and 6-5 summarize the plant level costs of installing L/LS and LSD FGD. At this plant unit 4 is the most cost effective to control because it is the largest unit and has the highest capacity factor. A L/LS FGD retrofit (90 percent SO_2 control) on boilers 1-4 would result in an annual reduction of 100,000 tons per year of SO_2. The data point on Figure 6-4 labeled low cost shows the impact of economies-of-scale when combining process areas as well as eliminating the spare towers.

Should LSD FGD with ESP upgrade be applied to units 1-3 and LSD with a new baghouse at unit 4, an estimated plant-level SO_2 reduction of 93,800 tons per year would be achieved assuming a 76 and 86 percent level of controls are achieved on boilers 1-3 and 4, respectively. The application of LSD FGD with new fabric filter at Conesville units 1-4 would result in an estimated plant-level SO_2 reduction of 97,000 tons per year assuming a 86 percent level of control is achieved. Because the unit 4 ESP is small (SCA of 181), it was assumed that a new fabric filter must be included in the LSD FGD retrofit.

6.2.2 Coal Switching/Blending

Table 6-9 presents the analyses for the coal used at Conesville in 1985 and the alternative coal used to evaluate coal switching. Because no ash analysis was provided by the plant, the effects of coal switching on boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate could not be estimated.

The ESP performance impacts were evaluated using the IAPCS model to determine the needed plate area. This plate area was compared to the existing area to determine the need for SO_3 conditioning or additional plate area. It was assumed that SO_3 conditioning would reduce the needed plate

TABLE 6-8. L/LS AND LSD FGD COSTS FOR CONESVILLE PLANT
(August 1987 Dollars)

		IAPCS Retrofit Costs[a]		
Case Description	Overall Retrofit Factor	Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.54	333.3-386.6	1,961-2,192	40.2-45.0
Boiler 2	1.54	333.3-386.6	1,779-1,982	36.5-40.7
Boiler 3	1.51	289.3-333.4	1,526-1,696	31.3-34.8
Boiler 4	1.55	173.2-205.6	703-810	14.4-16.6
LSD FGD (reuse ESP)				
Boiler 1	1.63	245.4	1,649	28.7
Boiler 2	1.63	245.4	1,479	25.7
Boiler 3	1.60	214.5	1,260	21.9
LSD FGD (new baghouse)				
Boiler 1	1.85	380.5	2,038	40.2
Boiler 2	1.85	380.5	1,824	36.0
Boiler 3	2.02	345.1	1,603	31.6
Boiler 4	2.07	239.5	751	14.8
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1-4	1.54	125.2	535	11.0

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

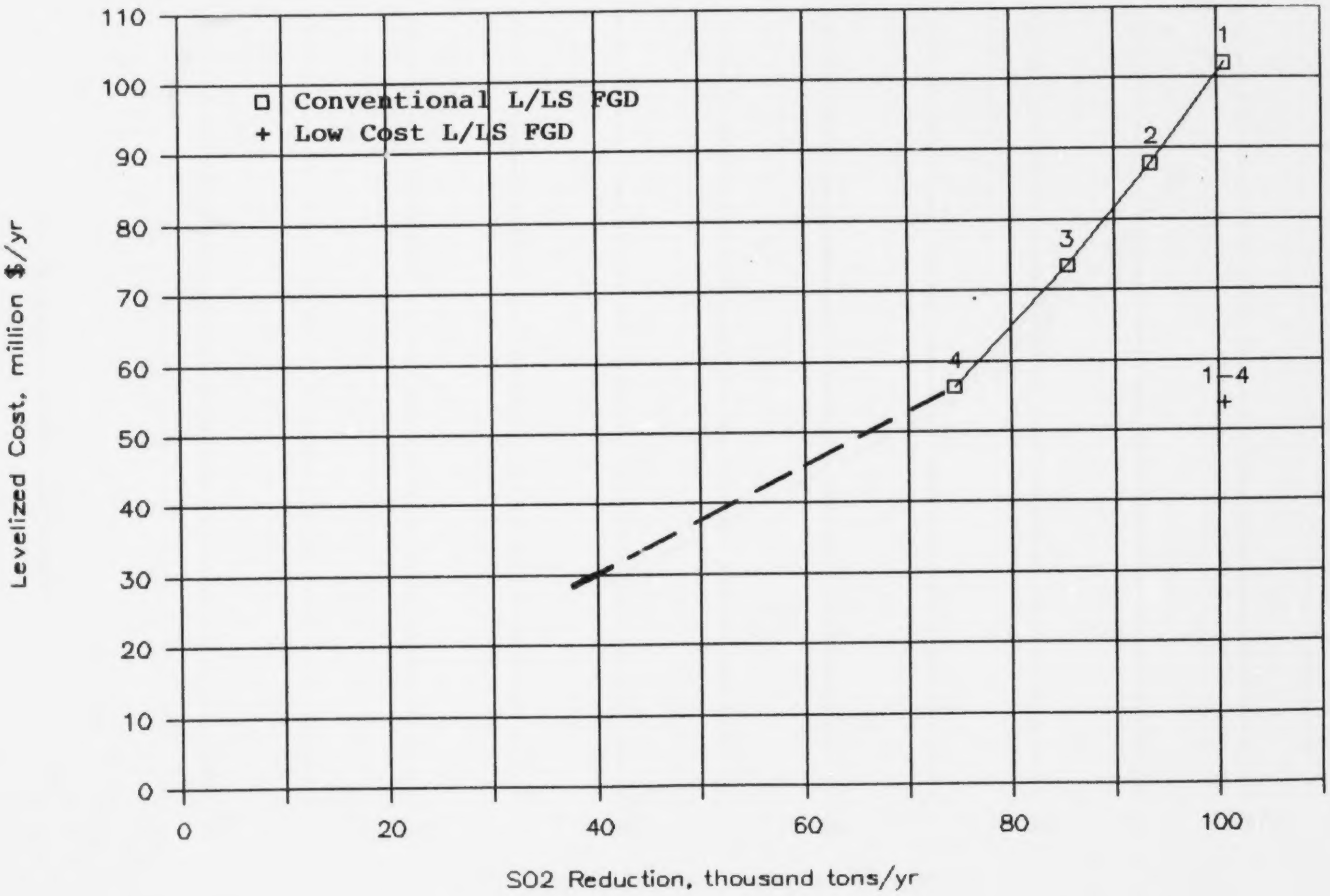

Figure 6-4. Conesville Plant L/LS cost versus SO_2 reduction.

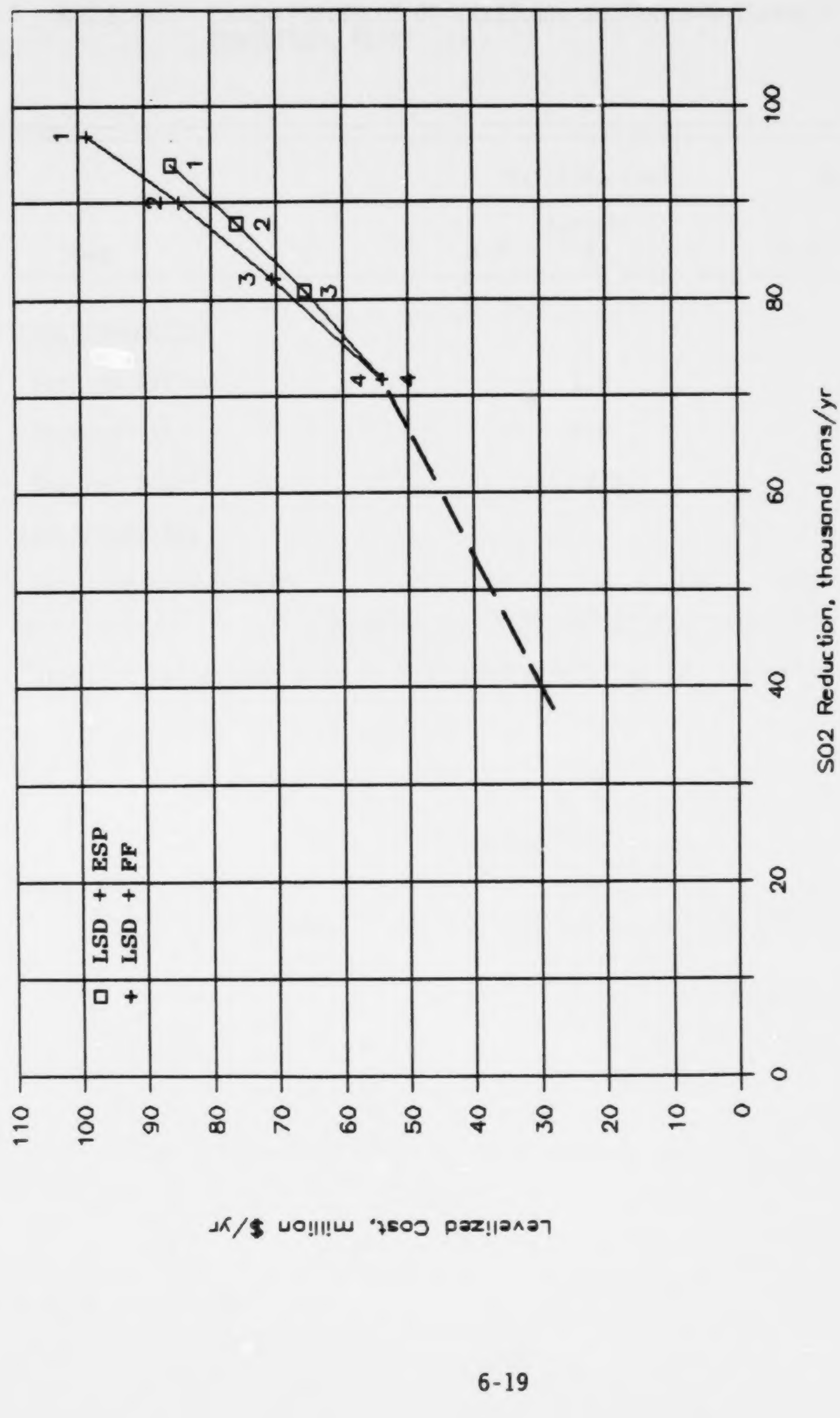

Figure 6-5. Conesville Plant lime spray dryer FGD cost versus SO_2 reduction.

TABLE 6-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR CONESVILLE PLANT

	Existing Coal			Switch Coal		
		Boiler			Boiler	
Item	1-2	3	4	1-2	3	4
COAL PARAMETERS						
Percent Sulfur		2.9			0.9	
Percent Ash		6.6			16.6	
Btu Per Pound		12,275			12,058	
ESP PARAMETERS						
Existing/Needed SCA[a]	333	306	181	232	229	247

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

area by 25 percent. It was estimated that SO_3 conditioning would sufficiently upgrade the existing ESPs for units 1, 2 and 3 for low sulfur service. However, an increase of 36 percent in ESP plate area would be required at unit 4.

The Conesville plant is currently equipped to handle low sulfur coal delivery and storage. There is ample space for storage, receiving, and handling and segregation of coal already exists. However, if coal blending was required, additional facilities would be needed.

Figure 6-6 is a presentation of plant level costs and SO_2 reduction for coal switching at the Conesville plant. Two curves were generated to show the impact of different coal fuel cost differentials. The lower curve represents a 1985 fuel cost differential of $7.06/ton between the existing coal ($37.83/ton) and the alternative low-sulfur coal ($44.89/ton). The remaining curves show the impact of an additional fuel cost differential of $15 per ton over the 1985 fuel cost differential of $7.06/ton. Approximately 77,000 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.4 pound per million Btu SO_2 emission rate. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 6-10.

Although the costs presented for unit 4 do include ESP plate area addition, these costs may be understated. In many cases where utilities have switched to low-sulfur coals, an entirely new ESP or baghouse is retrofit sized to operate without SO_3 conditioning. A new baghouse at unit 4 would add approximately 40 million dollars more in capital costs which increases annual costs by 30 percent at the $7.06 FCD and by 10 percent at the $22.06 FCD.

6.2.3 Physical Coal Cleaning

Physical coal cleaning was not evaluated for retrofit at the Conesville plant. Units 1-4 presently burn a washed coal, and without washability data on the run of mine and washed coal an analysis of additional coal cleaning cannot be conducted.

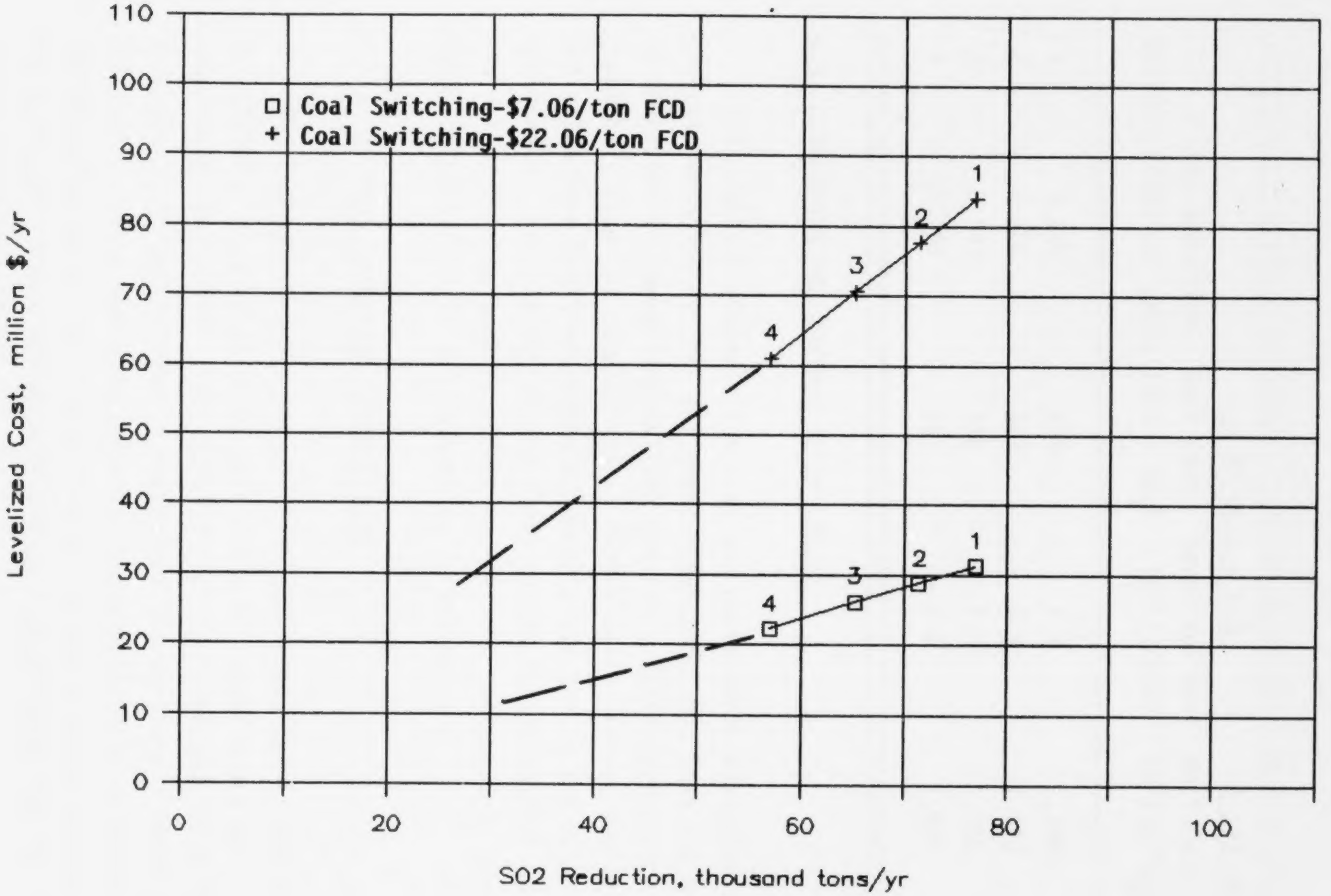

Figure 6-6. Conesville Plant coal switching costs versus SO_2 reduction.

TABLE 6-10. COAL SWITCHING COSTS FOR CONESVILLE PLANT
(August 1987 Dollars)

		@ $7.06/ton FCD		@ $22.06/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
1	5,500	459	7.2	1,168	18.3
2	6,200	443	6.9	1,144	17.9
3	8,300	458	7.2	1,158	18.1
4	56,900	392	6.1	1,073	16.8

6.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost and performance estimates for the SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a higher degree of uncertainty due to the lack of commercial scale data. For the Conesville Plant the following control technologies were evaluated: furnace sorbent injection (FSI) on boilers 1-4, duct spray drying (DSD) on boilers 1-4, and repowering on boilers 1-3.

6.3.1 Sorbent Injection Technologies

FSI and DSD technologies are being developed specifically for retrofit situations. Because of this, many costs of retrofit are built into the base case design and costs. The retrofit factors developed focus on scope adders that would not be included in developers' assumptions. These would include ESP/fabric filter additions, demolition/relocation of existing equipment/buildings, and conversion of the ash disposal system from wet to dry handling. Basic assumptions and cost adjustments for FSI and DSD are presented in table 6-11.

TABLE 6-11. SCOPE ADJUSTMENTS FOR FSI AND DSD AT CONESVILLE PLANT

Item	Boiler		
	1-2	3	4
BASIC ASSUMPTIONS			
Approximate access/congestion rank	High	High	Moderate
Can the existing ESP be upgraded?	Yes	Yes	No
Was a new baghouse evaluated for DSD?	Yes	Yes	Yes
Distance to final waste disposal (miles)	3	3	3
SCOPE ADDERS			
Install dry ash handling system for ESP reuse[a]	Yes	Yes	N/A[b]
New Stack	No	No	No
Additional duct work (ft)[c]	150	255	150
Duct demolition length (ft)	50	50	50
Building demolition area (ft^2)	0	0	0
ADDER COSTS AND RETROFIT FACTOR SUMMARY			
Scope adder costs for new baghouse (10^3 $)[d]	820	1,613	2,316
Scope adder costs for ESP reuse (10^3 $)[d]	1,165	1,493	N/A
Baghouse retrofit difficulty factor	1.34	1.34	1.34
ESP upgrade retrofit difficulty factor (for plate area addition)	1.55	1.55	N/A

[a] Not applicable when a new baghouse is installed.

[b] N/A = Not applicable.

[c] Not applicable when the existing ESP is used.

[d] June 1985 dollars.

6.3.1.1 Furnace Sorbent Injection--

FSI retrofit cost adders were developed for boilers 1-3. The sorbent was assumed to be a prepared calcitic hydrate material with the receiving/storage facilities located adjacent to the warehouses behind units 1 and 2. This location was chosen because of its access to existing roads and because solids conveying distances would be minimized. Approximately 250 to 500 feet of sorbent conveying line would be required to reach the injection day bins for boilers 1 through 3, respectively. The additional solid waste storage silos were located adjacent to the sorbent preparation area to allow for recycle of spent sorbent if this option were desired. It was assumed that the alkaline waste material could be disposed of at the existing landfill. Only furnace sorbent injection with ESP reuse was evaluated under this study. However, the unit 4 ESP is small (181 SCA) and not a likely candidate for upgrade. As such, this unit was not evaluated for FSI because the cost algothrithms do not estimate the cost of additional plate area.

6.3.1.2 Duct Spray Drying--

For duct spray drying (DSD) a lime slurry sorbent was evaluated with the sorbent receiving/storage/conveying systems being located as for FSI. A major parameter associated with the performance of DSD is to achieve sufficient duct residence time to obtain good SO_2 capture. The duct work prior to unit 1-4 ESPs might not have sufficient residence time to dry the injected sorbent. As such, two cases were considered: (1) reuse ESP with plate area addition; and (2) fabric filter replacement.

Another significant process parameter that would impact the effectiveness of DSD is the flue gas temperature available for evaporation of the slurry. For boilers 1-4, the air heater flue gas outlet temperature is near $300^{o}F$. As a result, it was estimated that units 1-4 could achieve 48 percent SO_2 removal with ESP reuse. The addition of fabric filters on units 1-4 would result in a higher SO_2 removal efficiency of 68 percent. As was the case for FSI, DSD with reuse of ESP was not evaluated for boiler 4 because of its small SCA.

6.3.1.3 Overall Retrofit Factors and Costs--

Table 6-12 presents the estimated retrofit costs for FSI and DSD. Figure 6-7 presents the cost of retrofitting FSI and DSD versus the plant level SO_2 reductions achieved. Two curves are presented to span the range of anticipated SO_2 removal (50 and 70 percent) and sorbent utilization (25 and 35 percent) for FSI. Boilers 1-3 SO_2 emissions would be reduced by 14,600 tons per year under the 50 percent SO_2 removal scenario and by 20,400 tons per year under the 70 percent SO_2 removal scenario. For the 50 percent SO_2 removal FSI case, the unit cost of control is $1,050 to $1,248 per ton of SO_2 removal. For the 70 percent SO_2 removal FSI case, the unit cost of control for these boilers would be $754 to $897 per ton of SO_2 removed.

Plant-wide SO_2 emission reductions for DSD with ESP reuse on boilers 1-3 and DSD with a new fabric filter on boiler 4 would be 69,800 tons per year. DSD with new fabric filters on boilers 1-4 would reduce plant-wide SO_2 emissions by 75,500 tons per year. Unit costs for DSD with ESP reuse range from $968 to $1216 per ton of SO_2 removed, and unit costs for DSD with new baghouses range from $652 to $1648 per ton of SO_2 removed.

6.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

Boilers 1-3 fit the repowering criteria in that they are small (<165 MW) and have been in service over 25 years. The heat rates for these units are moderate (~11,000 Btu/kWh), and the capacity factors are low (<40 percent) making these units good candidates. However, space near unit 3 is limited for construction of FBC or coal gasification units.

6.4 NO_x CONTROL TECHNOLOGIES

NO_x controls evaluated for the Conesville plant include the following technologies: low NO_x burners at boiler 3, natural gas reburn at boilers 1-2, and selective catalytic reduction at boilers 1-6. The site-specific factors affecting the performance and costs of retrofit NO_x combustion at the six Conesville plant boilers are summarized in table 6-1. Units 4-6 already employ overfire air for control of NO_x emissions.

TABLE 6-12. RETROFIT COSTS FOR FSI AND DSD FOR CONESVILLE PLANT
(August 1987 Dollars)

Case Description	IAPCS Capital Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50% removal)[a]				
Boiler 1	86.9	14.2	1,248	4,000
Boiler 2	86.9	13.2	1,157	4,500
Boiler 3	79.3	12.0	1,050	6,100
Furnace Injection (70% removal)[b]				
Boiler 1	87.5	14.3	897	5,600
Boiler 2	87.5	13.3	832	6,300
Boiler 3	79.6	12.0	754	8,500
Duct Spray Drying (reuse ESP)				
Boiler 1	65.4	13.3	1,216	3,800
Boiler 2	65.4	12.1	1,105	4,300
Boiler 3	61.9	10.6	968	5,800
Duct Spray Drying (new baghouse)				
Boiler 1	205.3	25.4	1,648	5,400
Boiler 2	205.3	22.8	1,483	6,000
Boiler 3	196.1	20.6	1,339	8,200
Boiler 4	138.2	10.0	652	55,900

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

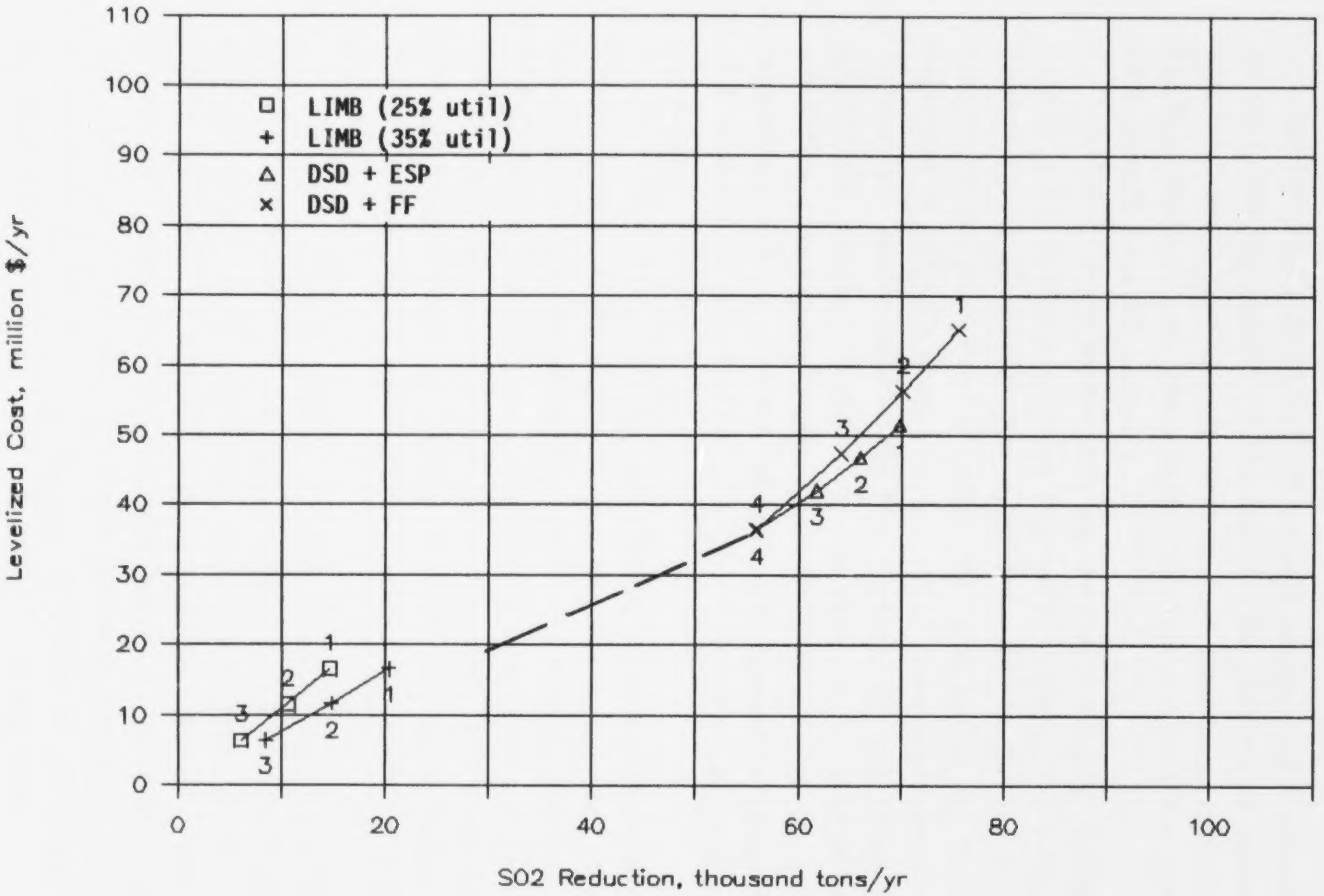

Figure 6-7. Conesville Plant FSI/DSD cost versus SO_2 reduction.

6.4.1 Low NO_x Combustion

Boiler 3 is a front wall-fired unit equipped with circular burners, and as such, low NO_x burners is the retrofit NO_x combustion control considered. Boilers 1 and 2 have cyclone furnaces, and therefore, natural gas reburning has been evaluated for these units. Boilers 4-6 were not evaluated because they already have NO_x controls.

Boiler 3, a dry bottom unit equipped with circular burners, is a good candidate for retrofit with low NO_x burners (LNB). The burner heat input (approximately 90 million Btu/hr) relative to the furnace depth and to the furnace height above the top burner row is as low as any wall-fired unit evaluated in the Ohio study. As a result, flame impingement on the rear furnace wall and/or superheater tube surfaces is less likely to be a significant problem. However, the low volatile fraction of the boiler heat input flux (approximately 240 Btu/sec-ft^2) relative to the bulk furnace residence time (1.5 seconds) and the upper furnace residence time (0.9 seconds) is intermediate to high. Carbon burnout problems therefore could occur.

For thermal NO_x effects, the furnace volumetric heat release rate (approximately 21,000 Btu/hr-ft^3) is low to intermediate. The burner zone heat release rate (approximately 310,000 Btu/hr-ft^2) also is low to intermediate. Considering fuel NO_x and mixing effects, the vertical burner spacing (approximately 8.5 feet) is fairly wide for a front wall-fired unit. Based on these factors, it appears that the furnace in Conesville boiler 3 is generally spacious and would tend to enhance the performance of a LNB retrofit.

The coal fired in Conesville boiler 3 is of relatively high sulfur content (approximately 3.0 weight-percent) and could create some corrosion problems during low NO_x operation. Boiler 3 operates at an intermediate excess air level (22 percent) with no slagging problems. The steam generation/furnace plan area slagging factor is less than 1,000 lb/hr-ft^2, well below the levels normally associated with bituminous coal combustion. It appears that ash slagging and fouling should not significantly inhibit the NO_x reduction performance of a LNB retrofit to this unit.

Based on these considerations, the NO_x reduction performance of a LNB retrofit at Conesville boiler 3 is estimated to be high (45 to 55 percent). This is due to the unit's relatively large furnace and the lack of slagging problems associated with the coal fired in boiler 3.

6.4.1.1 Natural Gas Reburning--

Natural gas reburning (NGR) was assumed to be applicable to boilers 1-2 at Conesville because these are cyclone furnaces. A NO_x emission reduction of 50 percent was assumed to be achievable with injection of 15 percent of the boiler heat input as natural gas, with the natural gas and overfire air being injected in the upper furnace section. The upper furnace residence time in units 1-2 is short and could lower the NO_x reduction achieved by a NGR retrofit.

6.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700^{0}F for coal-fired systems require the SCR system location to bypass part of the economizer or use a tail-end system with flue gas preheat.

For units 1-6, it was assumed that the tail-end SCR system would be used to minimize unit down times. Boiler 1-4 flue gases would be diverted after passing through the ESPs to the preheater and through the catalyst. Hot flue gas from the reactor would be cooled before returning to the chimney. For boiler 5-6, the flue gas would be diverted after the scrubbers. The catalytic reactors would be located behind each unit near each chimney.

Table 6-13 summarizes the SCR unit retrofit difficulty and scope adjustments for boiler units 1-6. The retrofit factor includes access and congestion, and underground obstruction considerations. A high retrofit factor was applied to the SCR costs at Conesville units 4-6 because of access and congestion considerations caused by the coal handling facilities. The

TABLE 6-13. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR CONESVILLE PLANT (August 1987 Dollars)

Item	Boiler 1	2	3	4	5	6
Site access and congestion for SCR reactor	Low	Low	Medium	High	High	High
SCOPE ADDER PARAMETERS						
Building demolition (1,000$)	61	61	0	0	0	0
Ductwork demolition (1,000$)	50	50	50	119	73	73
New duct length (feet)	100	100	100	100	100	100
New duct costs (1,000$)	565	565	664	1,573	1,074	1,074
New heat exchanger (1,000$)	2,131	2,131	2,517	6,093	4,119	4,119
Total scope adder costs (1,000$)	2,806	2,806	3,232	7,666	5,266	5,266
Retrofit factor for SCR	1.16	1.16	1.34	1.52	1.52	1.52
General facilities (percent)	13	13	13	13	13	13

area behind units 1-3 is less congested, and moderate to low difficulty factors were assigned. However, if an FGD system is also installed, all SCR retrofit difficulty factors would be high.

6.4.3 Summary of NO_x Control Costs

Table 6-14 and figure 6-8 present the annual cost of NO_x controls. LNC and NGR assume a 50 percent NO_x reduction for boilers 1-3. Application of LNC and NGR to all the boilers reduces NO_x emissions by 3,900 tons per year. The cost effectiveness of NGR ranged from 1,359 to 1,389 dollars per ton of NO_x removed. Application of SCR at boilers 1-3 would reduce NO_x emissions by 6,200 tons per year. Unit costs would exceed $5,000 per ton of NO_x removed.

TABLE 6-14. NO_X CONTROLS COSTS FOR CONESVILLE PLANT
(August 1987 Dollars)

NO_x Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X Reduced (tons/year)
Low NO_x Burner	3	50	16.0	473	1.0	1,100
Natural Gas Reburn	1	50	17.9	1,389	5.2	1,300
	2	50	17.9	1,359	5.1	1,500
Selective Catalytic Reduction	1	80	158.9	5,705	34	2,100
	2	80	158.9	5,071	30.2	2,300
	3	80	155.6	8,067	27.3	1,800

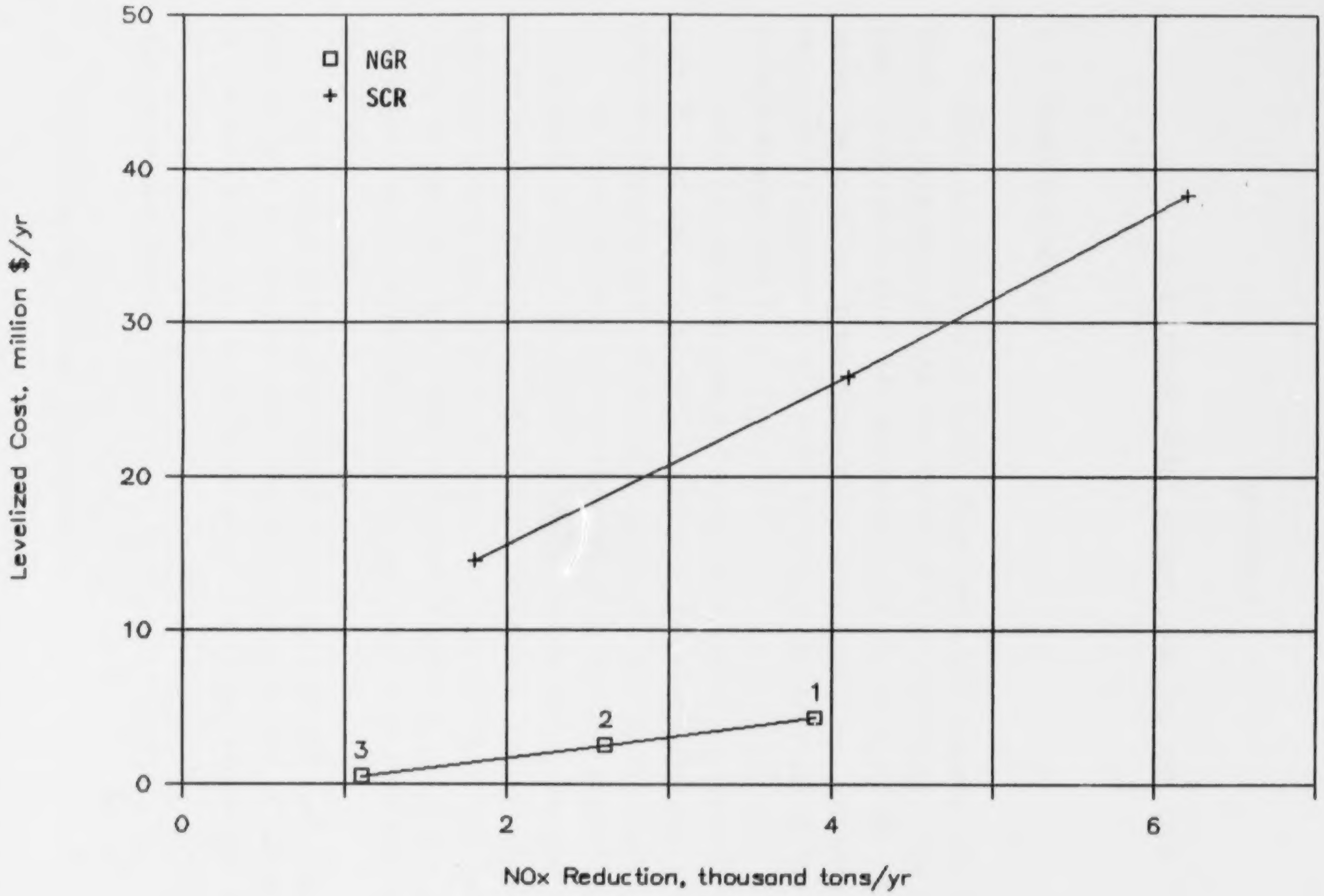

Figure 6-8. Conesville Plant NO_x controls costs versus NO_x reduction.

SECTION 7

J. M. STUART PLANT RETROFIT FACTORS AND COSTS

7.1 PLANT DESCRIPTION

Owned and operated by Dayton Power and Light Company, the J. M. Stuart Plant is located along the Ohio River east of Cincinnati. The plant is coal-fired with a total net generating capacity of 2,236 MW. Figure 7-1 shows the location of the four boiler units, turbines, and other facilities. The plant is bounded to the north by a major highway and to the east and west by undeveloped land.

Table 7-1 presents the key design and operational data obtained from EIA Form 767 and the site visit. In addition to verifying data, plant personnel provided numerous plot plans and diagrams for use in the study.

The plant receives all of its coal by barge from mines located primarily in Kentucky and West Virginia. Barge unloading facilities are located east of boiler/turbine unit 1. After being unloaded by rotary unloader, coal is conveyed to the coal pile located east of unit 1. This area holds a 70-day supply of coal at a plant load factor of 60 percent. A single coal stacker using three underground conveying systems moves coal from the coal pile to the crusher houses.

Ash disposal areas are located to the east of the coal pile and to the west of unit 4. The coal pile rain water run-off pond is located southwest of the coal pile. To the north of units 1-4 is the electrical switch yard and cooling water discharge canal. To the west of unit 4 is the chemical waste treatment basin.

7.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Stuart plant include the following: lime/limestone wet scrubbing (lime with and without

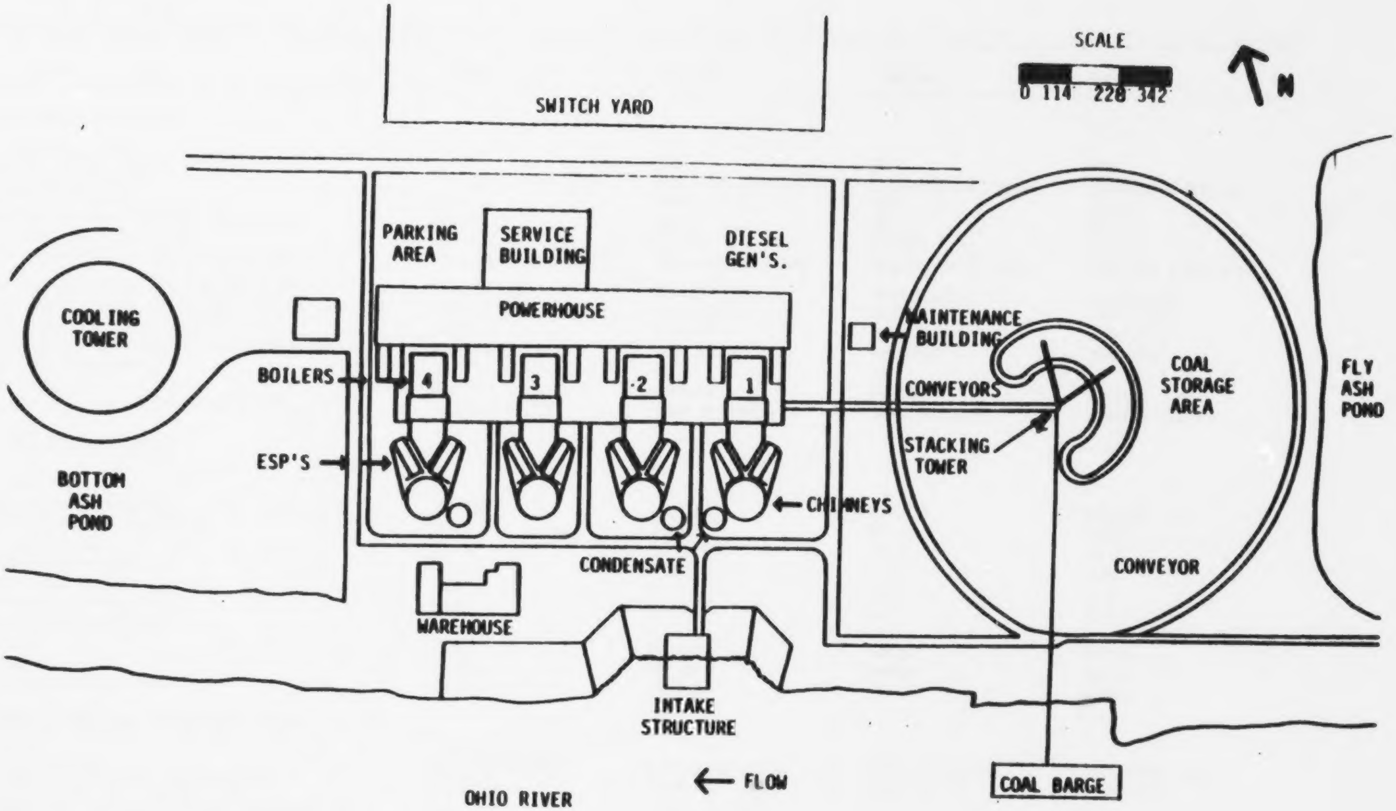

Figure 7-1. J. M. Stuart Plant plot plan.

TABLE 7-1. KEY DESIGN AND OPERATIONAL DATA FOR J. M. STUART PLANT

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4
BOILER AND STACK DATA				
Net generating capacity (MW)	585	585	585	585
Boiler manufacturer	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox
Installation date	1971	1970	1972	1974
Capacity factor (10 year projected)	53.2	56.4	57.7	58.1
Heat rate (Btu/kW-hr)	10,472	9,914	9,741	9,792
Boiler type/firing type/bottom type	Opposed wall/dry	Opposed wall/dry	Opposed wall/dry	Opposed wall/dry
Boiler dimensions, (ft, D x W x H[a])	39x63x120	39x63x120	39x63x120	39x63x120
Burner type/number of burners (# EL x #/EL)	Cell/2x12	Cell/2x12	Cell/2x12	Cell/2x12
Burner spacing (vert x horiz, ft)	12x8.8	12x8.8	12x8.8	12x8.8
Burner zone heat release rate (Btu/hr-ft^2)	783,000	783,000	783,000	783,000
Excess air (percent)	15	15	15	15
Draft type	Forced	Forced	Forced	Forced
Flue gas flow rate (1000 acfm @ °F)	1850 @ 240°F	1850 @ 240°F	1850 @ 240°F	1850 @ 240°F
FUEL AND SORBENT DATA				
Coal quality[b]				
Heat content (Btu/lb)	11,630	11,630	11,630	11,630
Volatile matter (percent)	35.7	35.7	35.7	35.7
Ash (percent)	13.5	13.5	13.5	13.5
Moisture (percent)	6.0	6.0	6.0	6.0
Sulfur (percent)	1.2	1.2	1.2	1.2
Nitrogen (percent)	1.0	1.0	1.0	1.0
Coal delivery methods				
Current	Barge	Barge	Barge	Barge
Design	Barge	Barge	Barge	Barge
Likely method for sorbent delivery	Truck	Truck	Truck	Truck
PARTICULATE CONTROL EQUIPMENT DATA				
Type of control	ESP/cold side	ESP/cold side	ESP/cold side	ESP/cold side
New/retrofit control installation	1974-76	1974-76	1974-76	1974-76
ESP specific collection area (ft^2/10^3 acfm)	290	290	290	290
Total plate area (10^3 ft^2)	435	435	435	435
Emission standards (lb/10^6 Btu)	0.1	0.1	0.1	0.1
ESP outlet emissions (lb/10^6 Btu)[c]	0.07	0.07	0.02-0.07	0.02-0.07
Design coal sulfur (percent)	3.5 - 5%	3.5 - 5%	3.5 - 5%	3.5 - 5%
Gas conditioning	yes	yes	yes	yes
Tested efficiency/design efficiency	99.9/99.9	99.9/99.9	99.9/99.9	99.9/99.9

(Continued)

TABLE 7-1. (CONTINUED)

Item	Boiler 1	Boiler 2	Boiler 3	Boiler 4
NITROGEN OXIDE CONTROL EQUIPMENT DATA				
NO_x Control Equipment	None	None	Low NO_x Cell burner	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA				
SO_2 Control Equipment	None	None	None	None
SOLID WASTE DISPOSAL DATA				
Ash Transport System Type				
Boiler Bottom Ash	Wet	Wet	Wet	Wet
Fly Ash	Wet	Wet	Wet	Wet
Ash Disposal Method	On-site	On-site	On-site	On-site
Existing Pond Capacity				
Estimated Distance to Off-Site Waste Disposal (miles)	1	1	1	1

[a] Furnace height from top of ash hopper to nose.

[b] Based on 1985 averages.

[c] Typical rate based on operating at the annual operating rate.

MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates.

7.2.1 Lime/Limestone and Lime Spray Drying FGD

7.2.1.1 Control Cases Evaluated--

Table 7-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD-FGD) SO_2 control cases evaluated. Retrofit factors and costs were developed for L/LS FGD and LSD FGD cases for boiler units 1 through 4. Retrofit costs were developed for LSD FGD with ESP reuse and LSD FGD with new fabric filters. Although the existing ESPs were assumed to be large enough for reuse, a significant increase in SO_2 removal can be achieved using fabric filters. For low sulfur coals, LSD with fabric filter can be lower in cost than L/LS FGD systems.

7.2.1.2 Layout of Equipment and Design Basis--

Figure 7-2 shows the general layout and location of the L/LS and LSD FGD equipment. Scrubbers would be located directly behind existing chimneys. Slurry preparation equipment would be located on the bottom ash pond adjacent to the cooling tower. Waste treatment equipment would be situated on the inactive fly ash pond east of the coal pile.

7.2.1.3 Scope Adjustments--

For L/LS and LSD FGD cases the following scope adjustments are necessary:

- demolition of bottom ash sluice lines (unit 1 = 300 ft., unit 2 = 600 ft., unit 3 = 900 ft., unit 4 = 1200 ft.),
- demolition of 36,400 ft^2 warehouses and loading dock behind units 3 and 4,

TABLE 7-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR J. M. STUART PLANT

Case Description	SO_2 Removed (%)	Coal Sulfur Wt %	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	1.2	25,200
Boiler 2	90	1.2	24,900
Boiler 3	90	1.2	24,300
Boiler 4	90	1.2	29,700
LSD FGD (new baghouse)			
Boiler 1	73	1.2	20,500
Boiler 2	73	1.2	20,300
Boiler 3	73	1.2	19,800
Boiler 4	73	1.2	24,200
LSD FGD (reuse baghouse)			
Boiler 1	53	1.2	14,900
Boiler 2	53	1.2	14,700
Boiler 3	53	1.2	14,400
Boiler 4	53	1.2	17,600
LOW COST CONTROLS			
L/LS FGD			
Boilers 1-2	90	1.2	50,200
Boilers 3-4	90	1.2	54,000

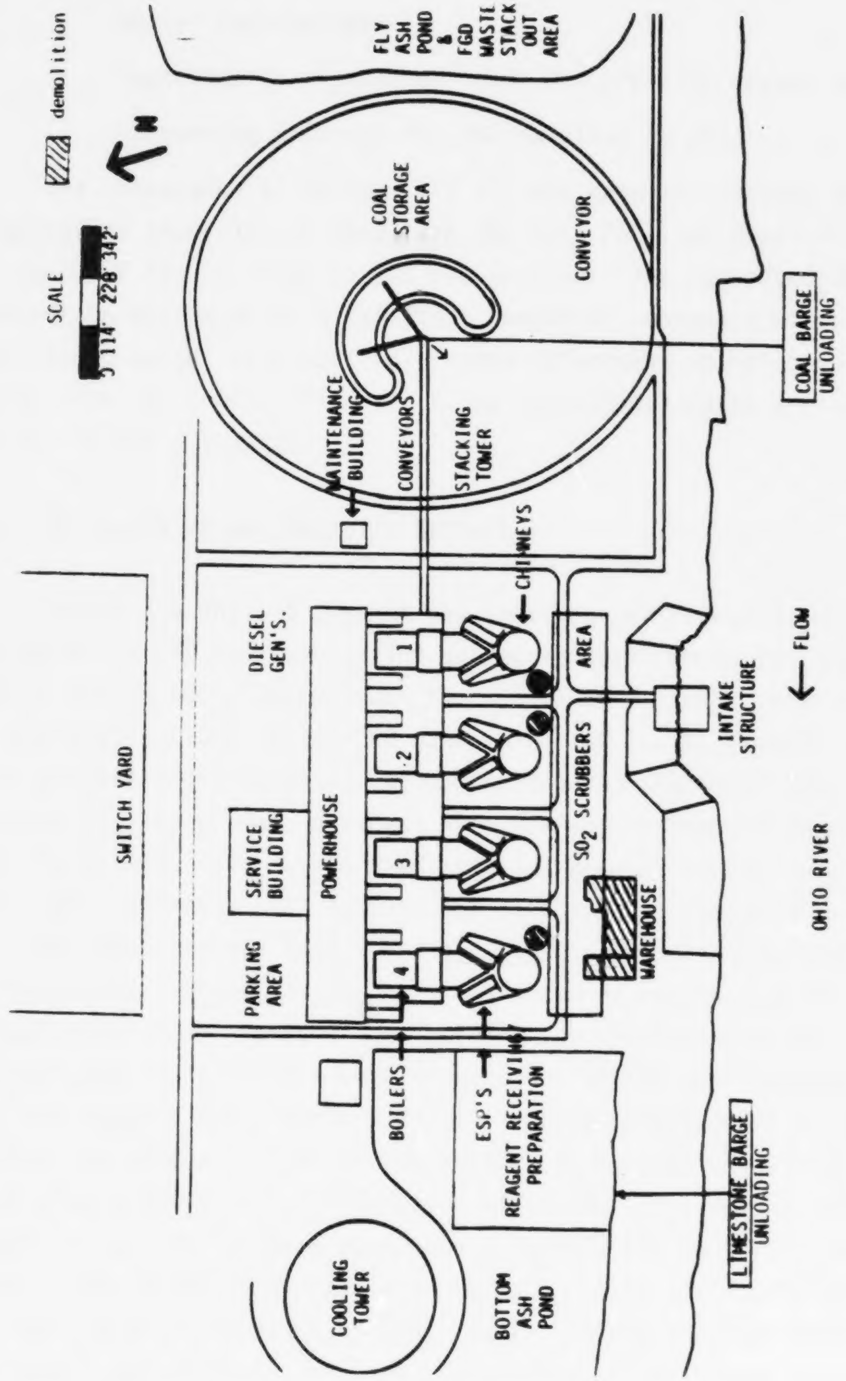

Figure 7-2. J. M. Stuart Plant L/LS plot plan.

- boiler reinforcement,
- installation of chimney liner for L/LS FGD cases, and
- conversion from wet fly ash handling to dry,

The conversion of boilers 1-4 fly ash handling systems from wet to dry disposal is necessary to stabilize the L/LS FGD lime based sludge and prevent plugging of sluice lines in LSD FGD systems. The estimated cost of this conversion was based on a TVA study comparing economics of wet versus dry ash handling disposal systems. This scope adjustment is not required for LSD FGD cases with new fabric filters. Scope adjustments costs are summarized in table 7-3 for all units.

7.2.1.4 Location and Retrofit Factors--

Tables 7-4 and 7-5 present the location and retrofit factors used for the L/LS and LSD FGD cases. The aggregate location factor presented in the column titled LOCF incorporates the following factors: seismic zone factor of 3, since this plant is located near an active fault; climate zone factor of 1.0; and labor and material factor for the Ohio/Kentucky area of 1.06. Soil factors vary by process area and FGD type and assume ground water at 3 feet for the reagent feed, waste handling, and general support equipment. For the other process areas soil factors for site-specific conditions were used.

Retrofit factors adjust for site-specific conditions such as underground obstructions, site accessibility, and ductwork tie-in distances. Small to medium underground factors were assumed for the Stuart plant. Unit 2 had higher underground obstruction factors due to the cooling water intake lines. For the reagent feed, waste handling, and general support equipment, the access and congestion factor was assumed to be base case, 1.02. For the remaining process areas, flue gas handling and SO_2 removal, low access/congestion factors were used. For LSD FGD with ESP reuse, a high access/congestion factor was used to reflect the difficulty of tieing in the ductwork before the existing ESP. Table 7-7 presents the duct tie-in distances and distances between process areas. Sufficient ductwork was

TABLE 7-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR J. M. STUART PLANT

Scope Adjustment	Description[a]
o Chimney liner	Chimney liner for all L/LS FGD cases on boilers 1-4 ($3.3/kW).
o Boiler reinforcement	Boiler reinforcement for all boilers ($4.1/Kw).
o Building demolition	Demolition of warehouses/loading dock/ bottom ash sluice lines for all FGD cases ($0.41-1.03/kW).
o Ash removal/conveyance	For all L/LS FGD and LSD FGD with reuse ESP cases, the wet fly ash conveying system was converted to dry handling ($7.77/kW).

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

TABLE 7-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR J. M. STUART PLANT

	All Units	Retrofit Factors Boiler #1-4			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.15	1.00	1.02	1.01-1.06	1.03-1.08
SO_2 Removal	1.07	1.00-1.03	1.10	1.00	1.10-1.13
Flue Gas Handling	1.08	1.03	1.10	1.30	1.47
Waste Handling	1.14	1.00	1.02	1.10-1.15	1.12-1.17
General Support Equipment	1.07	1.01-1.06	1.02	1.00	1.03-1.08
SCOPE ADJUSTMENTS					
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00
Chimney	N/A[f]	N/A	N/A	N/A	N/A
Demolition	1.06	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES					
Engineering - %			11.5		
General Facilities - %			10		

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 7-7 for distance assumptions used.
[e] AGGF = Aggregate Factor.
[f] N/A = Not applicable.

TABLE 7-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR J. M. STUART PLANT

Item	All Units LOCF[a]	Retrofit Factors Boiler #1-4 UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.34	1.00-1.01	1.02	1.01-1.06	1.04-1.08
SO_2 Removal	1.07	1.00-1.03	1.10	1.00	1.10-1.13
Flue Gas Handling	1.08	1.03	1.50	1.53	2.36[f]
General Support Equipment	1.07	1.00-1.01	1.02	1.00	1.03-1.12
SCOPE ADJUSTMENTS					
New Ash System	1.00	1.00	1.00	1.00	1.00
Chimney	N/A[g]	N/A	N/A	N/A	N/A
Baghouse	1.06	1.00	1.10	1.00	1.10
ESP Plate Addition	1.07	1.06	1.30-1.50	1.00	1.38-1.59
Demolition	1.06	1.00	1.00	1.00	1.00
Boiler Reinforcement	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES					
Engineering - %			11.5		
General Facilities - %			10		

---

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 7-7 for distance assumptions used.

[e] AGGF = Aggregate Factor

[f] Based on reusing ESP. If a new baghouse is used, the aggregate factor is 1.73

[g] N/A = Not applicable.

TABLE 7-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES EVALUATED FOR J. M. STUART PLANT

	All Units	Retrofit Factors Boiler #1-4			
Items	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.15	1.00	1.02	1.04	1.06
SO_2 Removal	1.07	1.01	1.10	1.00	1.11
Flue Gas Handling	1.08	1.03	1.10	1.30	1.47
Waste Handling	1.14	1.00	1.02	1.13	1.15
General Support Equipment	1.07	1.02	1.02	1.00	1.04

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See Table 7-7 for distance assumptions.

[e] AGGF + Aggregate Factor.

TABLE 7-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR J. M. STUART PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
L/LS FGD				
Boiler 1	225	225	900	1,500
Boiler 2	225	225	750	1,750
Boiler 3	225	225	500	2,000
Boiler 4	225	225	250	2,250
LSD FGD (new fabric filters)				
Boiler 1	225	450	1,000	N/A[c]
Boiler 2	225	450	750	N/A
Boiler 3	225	450	500	N/A
Boiler 4	225	450	250	N/A
LSD FGD (reuse ESP)				
Boiler 1	225	450	1,000	N/A
Boiler 2	225	450	750	N/A
Boiler 3	225	450	500	N/A
Boiler 4	225	450	250	N/A

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber out to the stack.

[c] N/A = Not applicable for spray drying FGD.

allocated to allow for road access between the chimneys and the absorber areas.

7.2.1.5 Overall Retrofit Factors and Costs--

Table 7-8 presents the overall retrofit factors and capital costs for all FGD cases. The ranges of costs shown for L/LS FGD reflect the different process options evaluated: conventional and adipic acid enhanced limestone FGD and conventional and MgO enhanced lime FGD. The LSD FGD costs include upgrading the ESPs and ash handling systems and the installation of new fabric filters to handle the additional particulate loading.

Figures 7-3 and 7-4 summarize the plant level costs of installing L/LS and LSD FGD. The data point labeled low cost shows the impact of scrubber optimization by eliminating the spare tower, maximizing tower size, and use of adipic acid additives to minimize capital costs.

The application of L/LS FGD would reduce plant level SO_2 emissions by approximately 104,000 tons per year assuming a 90 percent level of control. Application of LSD FGD at all units would reduce plant level SO_2 emissions by approximately 61,600 tons per year with ESP reuse and 84,800 tons per year with new fabric filters. Note that because Stuart burns a low-sulfur coal, the LSD FGD with new fabric filter has lower levelized costs than L/LS FGD.

7.2.2 Coal Switching/Blending

Table 7-9 presents the coal analyses for the coal used at the Stuart plant in 1985 and the alternative coal used to evaluate coal switching. The coals used at Stuart are Kentucky and West Virginia low-sulfur coals. Since the plant did not provide ash analysis, the impact of the following parameters on boiler operation could not be evaluated: boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal handling rate.

Electrostatic precipitator performance impacts were evaluated using the IAPCS model to estimate the necessary plate area. This plate area was then compared to an existing area to determine the need for SO_3 conditioning or additional plate area. The analyses assumed that SO_3 conditioning reduced

TABLE 7-8. L/LS AND LSD FGD COSTS FOR J. M. STUART PLANT
(August 1987 Dollars)

Case Description	Overall Retrofit Factor	IAPCS Retrofit Costs[a]		
		Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.43	161.0-190.1	1,429-1,631	13.1-14.9
Boiler 2	1.45	163.0-192.5	1,449-1,654	13.3-15.2
Boiler 3	1.44	162.0-191.3	1,469-1,676	13.5-15.4
Boiler 4	1.44	162.0-191.3	1,283-1,466	11.8-13.4
LSD FGD (new baghouse)				
Boiler 1	1.84[b]	181.3	1,462	10.9
Boiler 2	1.87[b]	183.8	1,489	11.1
Boiler 3	1.84[b]	181.3	1,506	11.2
Boiler 4	1.84[b]	181.4	1,273	9.5
LSD FGD (reuse ESP)				
Boiler 1	1.70[c]	145.8	1,634	8.8
Boiler 2	1.72[c]	149.6	1,678	9.1
Boiler 3	1.71[c]	148.8	1,709	9.2
Boiler 4	1.70[c]	146.6	1,422	7.7
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1-2	1.45	103.5	849	7.8
Boilers 3-4	1.44	103.5	806	7.4

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] Includes impact of new baghouse.

[c] No plate area increase needed.

TABLE 7-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR J. M. STUART PLANT

	Existing Coal	Switch Coal	Cleaned Coal
Item	Boilers 1-4	Boilers 1-4	Boilers 1-4
COAL PARAMETERS			
Percent Sulfur	1.2	0.9	1.1
Percent Ash	14.1	8.8	3.9
Btu Per Pound	11,484	12,554	12,963
ESP PARAMETERS			
Existing/Needed SCA[a]	290	213	213

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

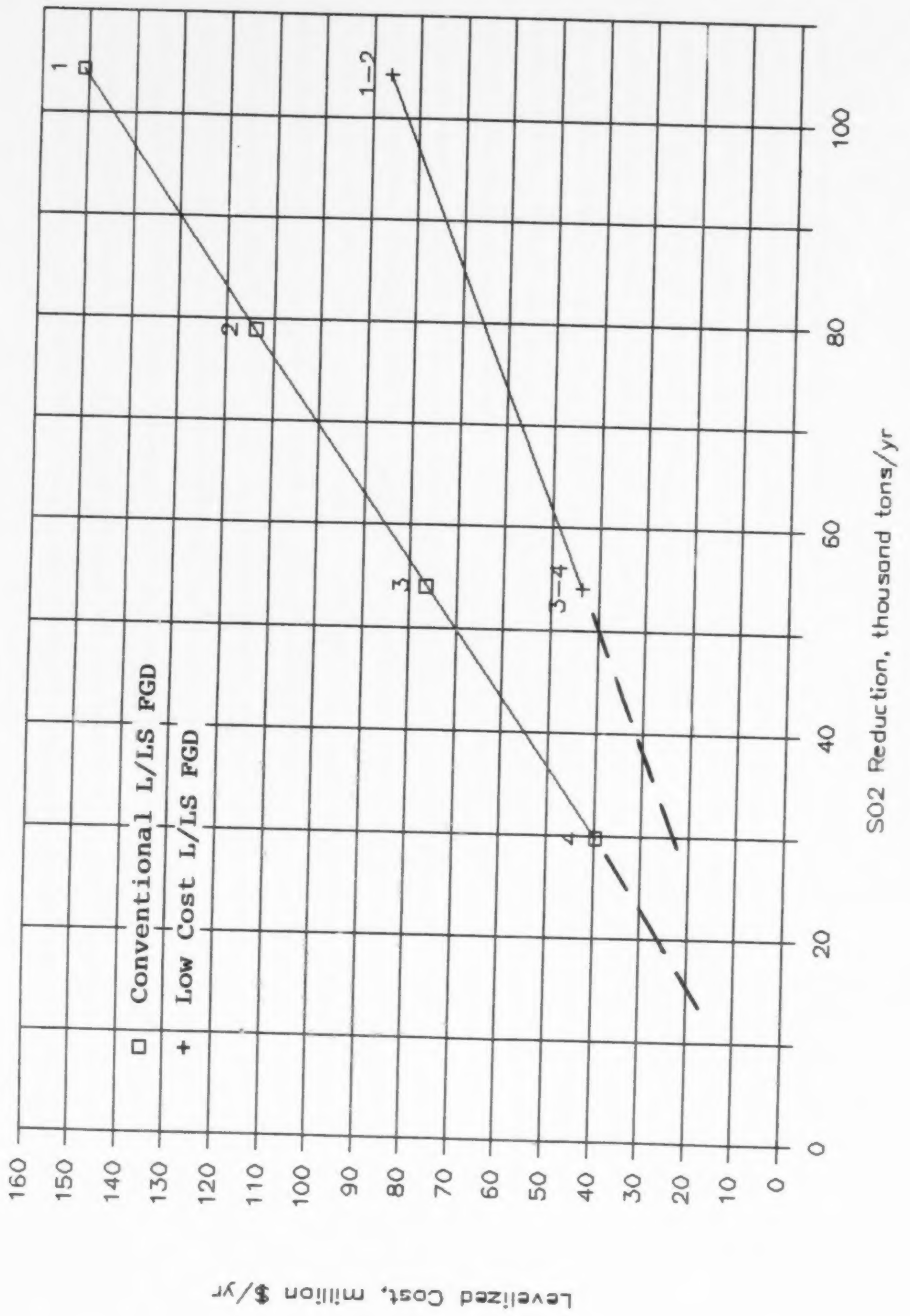

Figure 7-3. J. M. Stuart Plant L/LS cost versus SO_2 reduction.

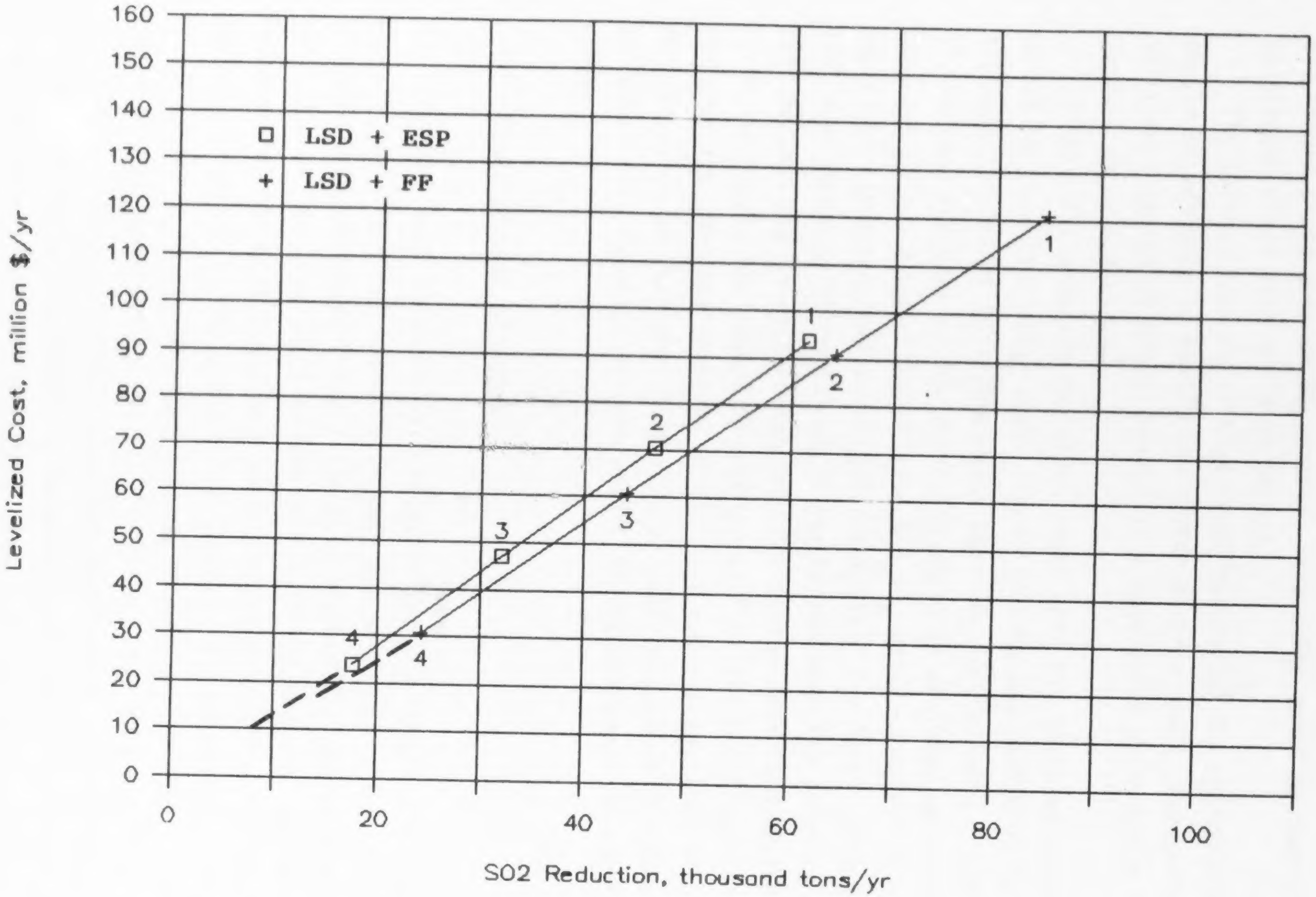

Figure 7-4. J. M. Stuart Plant lime spray dryer FGD cost versus SO_2 reduction .

the needed plate area by 25 percent. The IAPCS model estimated that no additional plate area would be needed.

The current coal facilities (coal receiving/storage/handling) at Stuart should be adequate to handle low sulfur eastern coals transported by barge. Additional equipment may be needed if a segregated pile system or blending facilities were desired.

Figure 7-5 presents the plant level cost and emission reduction for switching to a low-sulfur coal. These include SO_3 conditioning costs, although the Stuart boilers already have SO_3 conditioning. Approximately 37,400 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.4 pound per million Btu SO_2 emission rate. Plots show the impact of different coal price differentials. The lower curve represents a 1985 fuel price differential of $3 per ton between the existing coal ($43.60/ton) and an eastern Kentucky low-sulfur coal ($46.62/ton). The upper curve represents the impact of additional fuel price differentials of $15 per ton over the 1985 differential of $3. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 7-10. The different unit capacity factors result in the different cost-effectiveness values.

7.2.3 Physical Coal Cleaning

Physical coal cleaning was evaluated for the Stuart plant using a similar coal for which washability data was available. The cost of cleaning this coal was estimated using a TVA developed coal cleaning model and was incorporated into the IAPCS as one of the 12 cleaned coal options. It was assumed that the coal would be cleaned at the mine and no refuse disposal would be required at the plant. The cleaned coal parameters were input into the IAPCS model to estimate performance impacts on the ESPs. IAPCS estimated that with SO_3 conditioning the SCA of the existing ESPs would be adequate.

Figure 7-5 also presents the IAPCS results for physical coal cleaning for the four boilers at Stuart. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal. The costs do include the estimated increase in coal cost for the cleaning operation ($4.53 per ton) and the cost of SO_3

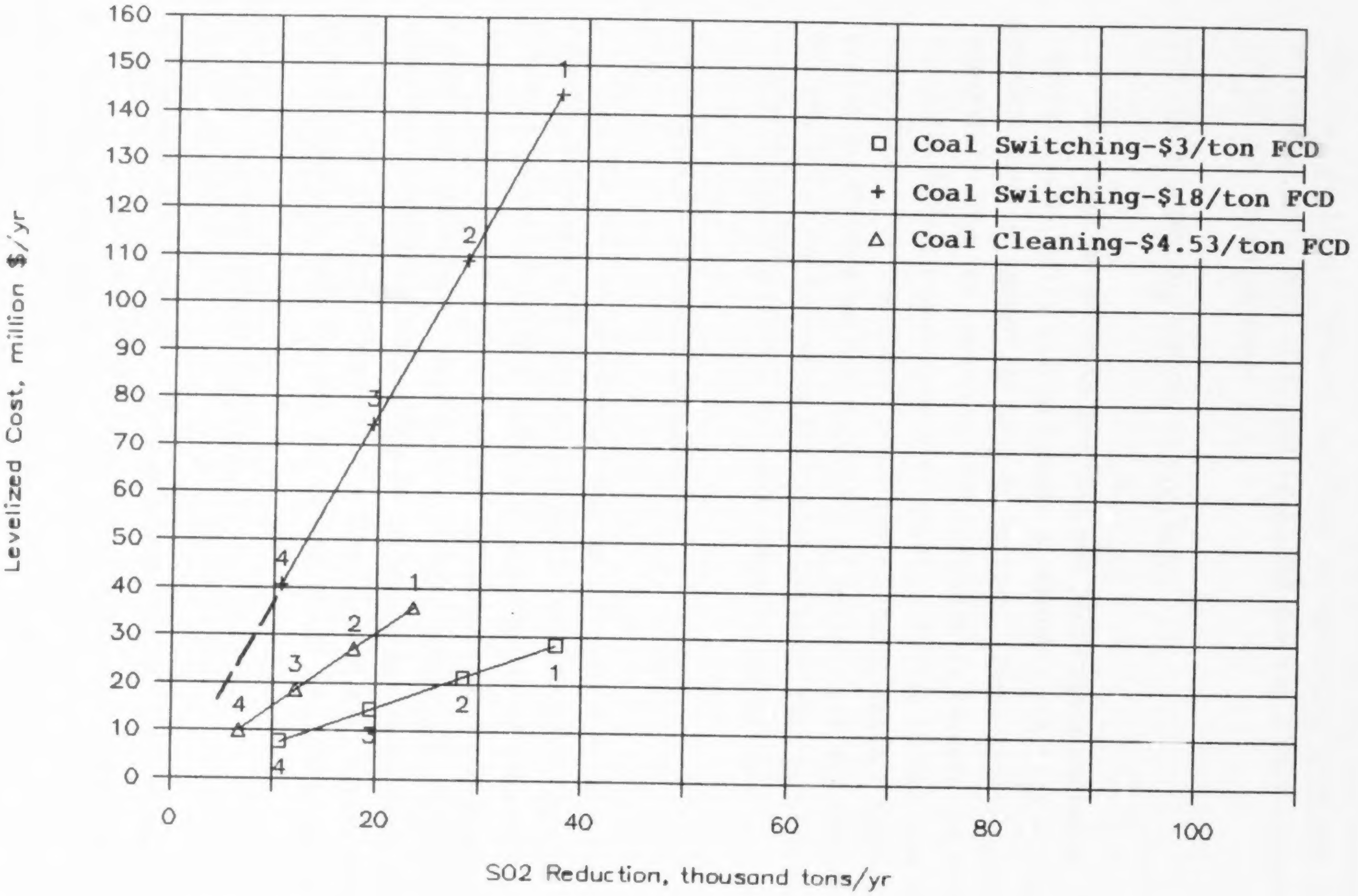

Figure 7-5. J. M. Stuart Plant coal switching/cleaning costs versus SO_2 reduction.

conditioning even though the plant already uses SO_3 conditioning. Cleaning the coal at Stuart reduces the plant SO_2 emissions by 23,500 tons per year at an average unit cost of $1,502 to $1,556 per ton. Cost estimates for each boiler are shown in table 7-11.

7.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost and performance estimates for the SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a higher degree of uncertainty due to the lack of commercial scale data. For the Stuart plant the following control technologies were evaluated: furnace sorbent injection at boilers 1-4 and duct spray drying at boilers 1-4. The following discussion presents the retrofit issues and the cost/performance estimates for each retrofit technology.

7.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. As such, many retrofit factors are built into the base case design and costs. Retrofit factors developed for these technologies at Stuart focus on determining and evaluating the need for scope adders which would not be included in developers' assumptions. These adders are ESP/fabric filter additions, demolition/relocation of equipment/buildings, and conversion of wet fly ash handling systems to dry handling/storage. Basic assumptions and cost adjustments made for FSI and DSD at Stuart are presented in table 7-12.

7.3.1.1 Furnace Sorbent Injection--

Sorbent was assumed to be a prepared calcitic hydrate material with the receiving/storage facilities located on the ash sluice pond adjacent to unit 4. This location was chosen for easy access to existing roads and to minimize solids conveying distances. Approximately 200 to 1,100 feet of sorbent conveying line would be required to reach the injection day bins for

TABLE 7-10. COAL SWITCHING COSTS FOR J. M. STUART PLANT
(August 1987 Dollars)

		@ $3/ton FCD		@ $18/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1	9,000	763	2.5	3,862	12.7
2	9,000	764	2.5	3,865	12.7
3	8,700	769	2.5	3,874	12.7
4	10,700	736	2.4	3,811	12.5

TABLE 7-11. PHYSICAL COAL CLEANING COSTS FOR J. M. STUART PLANT
(August 1987 Dollars)

Boiler	SO_2 Reductions (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1	5,700	1,546	3.2
2	5,600	1,549	3.2
3	5,500	1,556	3.2
4	6,700	1,502	3.1

TABLE 7-12. SCOPE ADJUSTMENTS FOR FSI AND DSD AT J. M. STUART PLANT

Item	Boiler 1 and 4	Boiler 2 and 3
BASIC ASSUMPTIONS		
Approximate access/congestion rank	Low	Moderate
Can the existing ESP be upgraded?	Yes	Yes
Was a new baghouse evaluated for DSD?	Yes	Yes
Distance to final waste disposal (miles)	1	1
SCOPE ADDERS		
Install dry ash handling system[a]	Yes	Yes
New Stack	No	No
Additional duct work (ft)[b]	350	350
Duct demolition length (ft)	50	50
Building demolition area (ft^2)	0	0
ADDER COSTS AND RETROFIT FACTOR SUMMARY		
Scope adder costs for new baghouse (10^3 \$)[c]	4,175	4,175
Scope adder costs for ESP reuse (10^3 \$)[c]	4,794	4,794
Baghouse retrofit difficulty factor	1.10	1.13
ESP upgrade retrofit difficulty factor (for plate area addition)	1.38	1.59

[a] Not applicable when a new baghouse is installed.

[b] Not applicable when the existing ESP is used.

[c] June 1985 dollars.

boilers 4 and 1, respectively. The additional solid waste storage silos were located adjacent to the sorbent preparation area to allow for recycle of spent sorbent. It was assumed that the alkaline waste material could be disposed at a landfill across the road from the plant.

Boilers 1-4 currently use SO_3 flue gas conditioning to meet the particulate emission standard and have ESPs with SCA of 290. The IAPCS cost model assumes that with humidification and tune-up no increase in the SCA would be required. The cost model estimates include the cost of humidification tune-up and the costs for converting the ash disposal system from wet to dry handling.

7.3.1.2 Duct Spray Drying--

Duct spray drying using a lime sorbent was evaluated for retrofit at boilers 1-4. The sorbent receiving and storage facilities would be in the same location as for LSD FGD. Approximately 200-1,100 feet of slurry line would be required to pump the slurry to the recirculation/injection tanks at the duct injection points.

A major consideration associated with the performance of DSD is sufficient flue gas temperature and duct residence time to obtain good SO_2 capture and complete drying of the lime droplets. The Stuart plant boilers have low air heater flue gas outlet temperatures (~240°F) and short flue gas duct runs to the ESPs. The IAPCS model estimates, based on the low flue gas temperature, that only a 36 percent SO_2 removal may be achieved with reuse of the ESPs and a 60 percent removal may be achieved with the addition of fabric filters. The IAPCS model estimates that if the ESPs are reused no additional plate area would be needed. However, because duct residence time of the flue gas from the air heater outlet to the ESPs is less than one second, reuse of the ESPs may not be feasible. Therefore, the retrofit of fabric filters after the existing ESPs was also evaluated. This situation would provide sufficient flue gas residence time for good SO_2 removal.

7.3.1.3 Overall Retrofit Factors and Costs--

Table 7-13 summarizes the overall retrofit factors and costs for FSI and DSD with ESP reuse and with new fabric filters. Figure 7-6 presents the cost of retrofit versus the plant level SO_2 reductions achieved. Application of FSI at the four Stuart boilers would reduce SO_2 emissions by 58,000 tons per year (50 percent removal) or 81,000 tons per year (70 percent removal). Application of DSD to all of the Stuart boilers would result in SO_2 reduction of 42,000 tons per year for DSD with ESP reuse and 69,700 tons for DSD with fabric filters.

7.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG)

All four units at Stuart are too large (585 MW) and new to be considered for life extension through FBC/CG.

7.4 NO_x CONTROL TECHNOLOGIES

This section presents the cost and performance estimates developed for NO_x controls at the Stuart plant. Control applicability and performance are discussed in the following sections for each boiler. The controls evaluated are as follows: low NO_x burners for units 1-4 and selective catalytic reduction at boilers 1-4. The site-specific factors affecting the performance of retrofit NO_x combustion controls at the four Stuart plant boilers are summarized in table 7-1.

7.4.1 Low NO_x Burners

Boilers 1-4 are equipped with cell burners in an opposed wall-fired configuration and all are dry bottom furnaces. A low NO_x cell burner is being developed for retrofit. Currently, boiler 3 has one low NO_x cell burner which was installed to test the mechanical reliability and performance effects under commercial operation. The four boilers have burner heat inputs of approximately 110 million Btu/hr, which, relative to the furnace depth (39 feet), is intermediate to high for a cell burner application. The burner

TABLE 7-13. RETROFIT COSTS FOR FSI AND DSD FOR J. M. STUART PLANT
(August 1987 Dollars)

Case Description	IAPCS Captial Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50 % removal)[a]				
Boiler 1	45.8	4.6	911	14,000
Boiler 2	47.2	4.7	928	13,900
Boiler 3	47.2	4.8	940	13,500
Boiler 4	45.8	4.3	844	16,500
Furnace Injection (70 % removal)[b]				
Boiler 1	45.9	4.7	655	19,600
Boiler 2	47.3	4.8	688	19,400
Boiler 3	45.9	4.3	607	18,900
Boiler 4	39.6	4.1	577	23,100
Duct Spray Drying (reuse ESP)				
Boiler 1	32.3	3.2	860	10,100
Boiler 2	33.3	3.2	877	10,100
Boiler 3	33.3	3.3	892	9,800
Boiler 4	32.3	2.8	771	12,000
Duct Spray Drying (new baghouse)				
Boiler 1	101.7	6.9	1,127	16,800
Boiler 2	103.2	7.0	1,146	16,700
Boiler 3	101.4	7.1	1,155	16,300
Boiler 4	101.5	6.1	991	19,900

[a] This case presented correspond to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

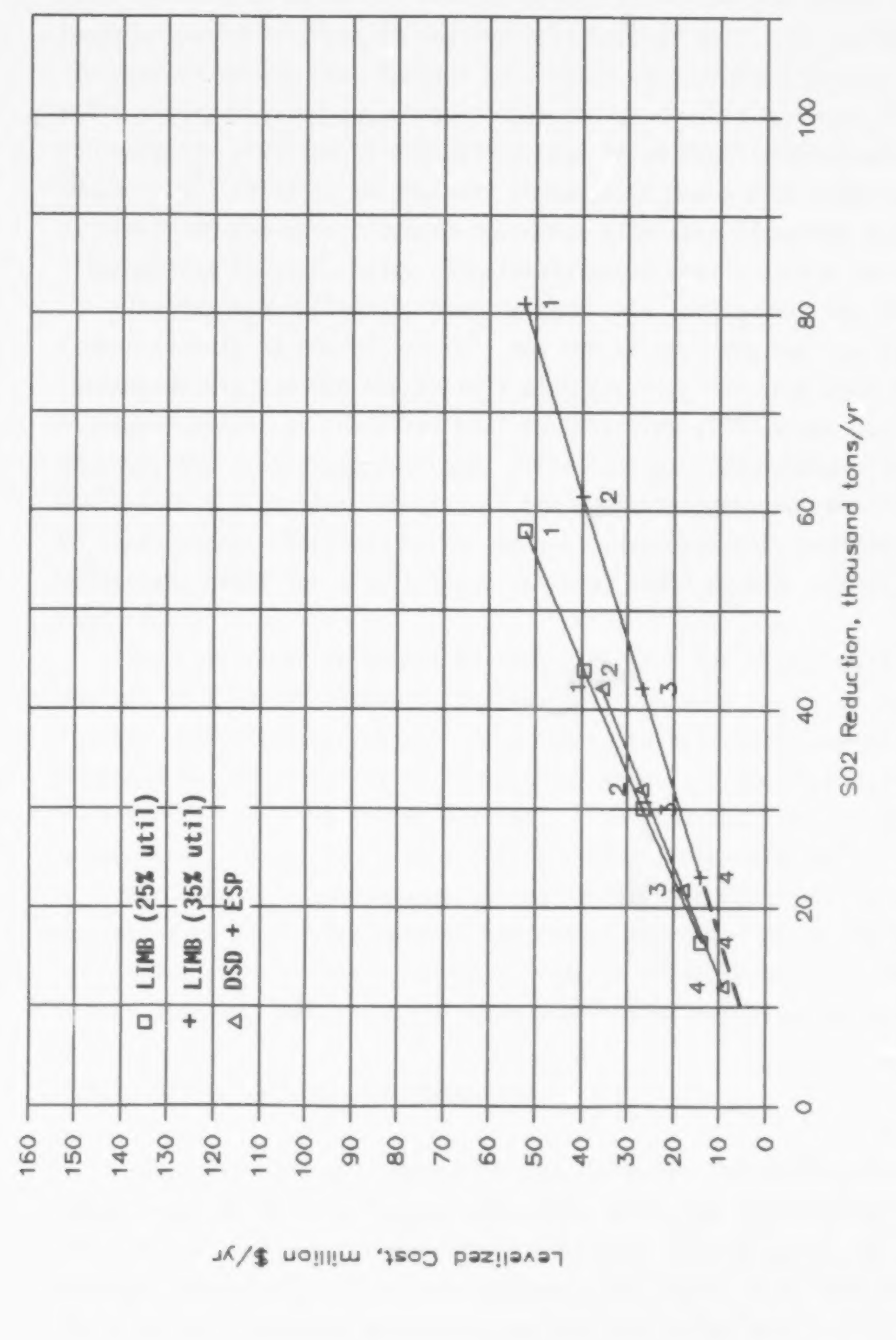

Figure 7-6. J. M. Stuart Plant FSI/DSD cost versus SO_2 reduction.

heat input relative to the furnace height above the top burner row (approximately 72 feet) is low for this type of unit. It appears that flame impingement on the rear furnace wall could be a problem for a LNB retrofit, while impingement on superheater tube surfaces would be less likely. The non-volatile fraction of the boiler heat input flux (approximately 380 Btu/sec-ft^2) relative to the bulk furnace residence time (approximately 1.9 seconds) and the upper furnace residence time (approximately 1.4 seconds) is intermediate to high, which conceivably could create carbon burnout problems.

The furnace volumetric heat release rate for thermal NOx effects (approximately 23,000 Btu/hr ft^2) and the burner zone heat release rate (approximately 780,000 Btu/hr-ft^2) both are high for this type of unit. Nitrogen content of the fired coal is quite low (1.0 weight percent); however, the fuel oxygen/nitrogen ratio is high. LNB combustion staging would affect a smaller fraction of the fuel nitrogen, potentially limiting NO_x reductions. Vertical burner spacing (approximately 5.2 feet) also is relatively tight for a wall-fired unit and could have an effect on fuel NO_x reductions.

The coal fired in Stuart boilers 1-4 has a low to moderate sulfur content (1.2 weight percent), thereby creating some corrosion problems during low NO_x combustion operation. Slagging could occur from uneven blending of Ohio and out-of-state coals, since these units operate at relatively low excess air levels (15 volume percent). This results from a high steam generation/furnace plan area slagging factor (1800 lb/hr-ft^2).

NO_x reduction performance or LNB retrofit at Stuart boilers 1-4 is estimated to be intermediate to low (25-35 percent), which can be attributed to shallow furnace depth, high heat release rates, high fuel O/N ratio, tight burner spacing, and potential furnace corrosion and slagging problems.

7.4.2 Selective Catalytic Reduction

Selective catalytic reduction was evaluated for units 1-4. Equipment items required for a selective catalytic reduction (SCR) system would include the catalyst and catalytic reactor; controls; and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Because the Stuart boilers are large baseload units, it was assumed that a tail-end SCR unit would be a less costly option because downtime would be minimized. Table 7-14 summarizes the key information used to develop the SCR unit retrofit difficulty and scope adjustments. There is sufficient space behind each boiler to locate the catalytic reactors and other equipment. The duct lengths allow for road access between the reactors and chimneys. A slightly higher general facilities percentage was assigned to units 1 and 2 because of the underground cooling water intake lines.

7.4.4 Summary of NO_x Control Costs

Table 7-15 and figure 7-7 present the annual cost of NO_x controls. LNB costs assume a 35 percent NO_x reduction while SCR assumes an 80 percent reduction. Application of LNB to the four Stuart boilers was estimated to reduce NO_x emissions by 18,200 tons per year at a unit cost of $167-204 per ton of NO_x removed. Application of SCR would reduce NO_x emissions by 41,600 tons per year if 80 percent reduction can be achieved; the cost per ton of NO_x removed would be $2,977 to $3,600.

TABLE 7-14. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR J. M. STUART PLANT

(August 1987 Dollars)

ITEM	Boiler 1	Boiler 2	Boiler 3	Boiler 4
Site access and congestion for SCR reactor	Low	Low	Low	Low
SCOPE ADDER PARAMETERS	---		---	
Building demolition (1,000$)	0	0	0	0
Ductwork demolition (1,000$)	102	102	102	102
New duct length (feet)	450	450	450	450
New duct costs (1,000$)	6,267	6,267	6,267	6,267
New heat exchanger (1,000$)	5,379	5,379	5,379	5,379
Total scope adder costs (1,000$)	11,747	11,747	11,747	11,747
Retrofit factor for SCR	1.16	1.16	1.16	1.16
General facilities (percent)	17	17	13	13

TABLE 7-15. NO_X CONTROLS COSTS FOR J. M. STUART PLANT
(August 1987 Dollars)

NO_x Control	Boiler Number	NO_x Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_x)	Annual Cost (mills/kWh)	NO_x Reduced (tons/year)
Low NO_x Burner	1	35	7.7	197	0.3	4,400
	2	35	7.7	199	0.3	4,400
	3	35	7.7	204	0.3	4,200
	4	35	7.7	167	0.3	5,200
Selective Catalytic Reduction	1	80	85.7	3,497	12.8	10,000
	2	80	85.7	3,527	12.9	10,000
	3	80	84.4	3,600	13.2	9,700
	4	80	84.4	2,977	10.9	11,900

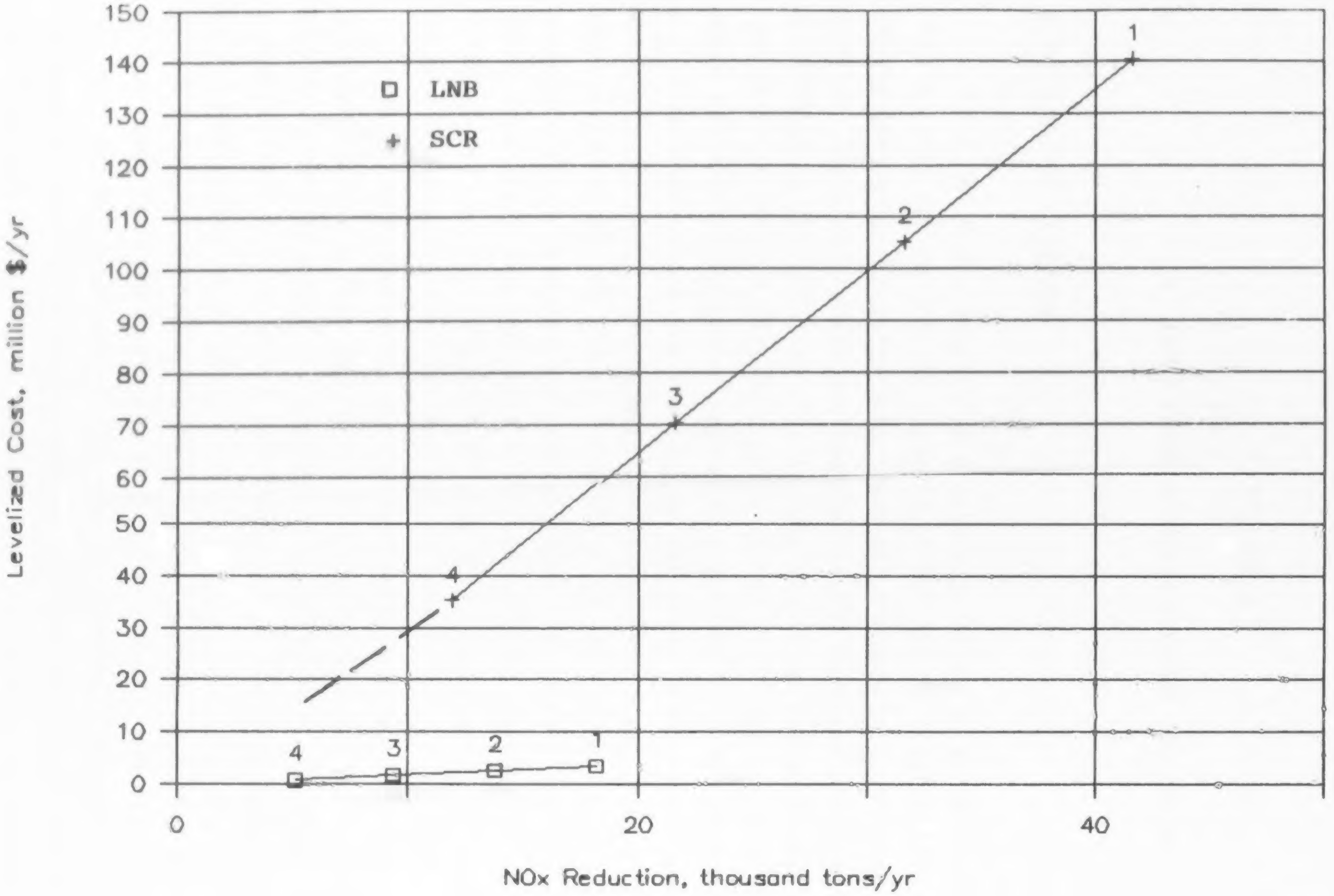

Figure 7-7. J. M. Stuart Plant NO_x controls cost versus NO_x reduction.

SECTION 8

E. W. BROWN PLANT RETROFIT FACTORS AND COSTS

8.1 PLANT DESCRIPTION

The E. W. Brown generating plant, consisting of three coal-fired boilers with a total net generating capacity of 659 MW, is located in a relatively remote part of central Kentucky, just off Highway 68 South near the town of Burgin. The plant, owned and operated by the Kentucky Utilities Company, is surrounded by pasture land on all sides except to the northeast where a small reservoir is located (Dix Dam area). Total plant area is over 500 acres (of which only about 300 acres are usable according to plant personnel).

Figure 8-1 shows the location of the power plant, major associated auxiliary equipment, and support structures; the plant fence line is beyond the boundaries of the figure. The plant is located on a knoll and is surrounded by a 28 mile long reservoir/dam, an 80-acre ash pond and a gorge. Three open areas are available within the plant: one to the west of boiler 3, one to the northeast of turbine 3, and one to the southeast of cooling tower 2 and north of the unit 2 ESPs.

Table 8-1 presents key design and operational data for the existing equipment at Brown Station. Units 1, 2, and 3 are all pulverized coal-fired boilers with net dependable generating capacities of 100, 156, and 403 MW, respectively. Units 1 and 2 were installed in 1957 and 1963, respectively. Unit 3 was installed in 1971.

All boilers burn the same 1.92 percent sulfur coal, which is delivered to the plant from the southwest by truck or by rail (currently, most comes in by truck due to lower cost). The coal is unloaded, crushed and then conveyed to the coal pile area east of the parking lot or sent directly to an operating unit. Total dead and live storage capacity is between 60 and 90 days. The coal pile area is about 30 acres; additional pile storage area is is available if needed. Coal is conveyed from the pile area to units 1 and 2

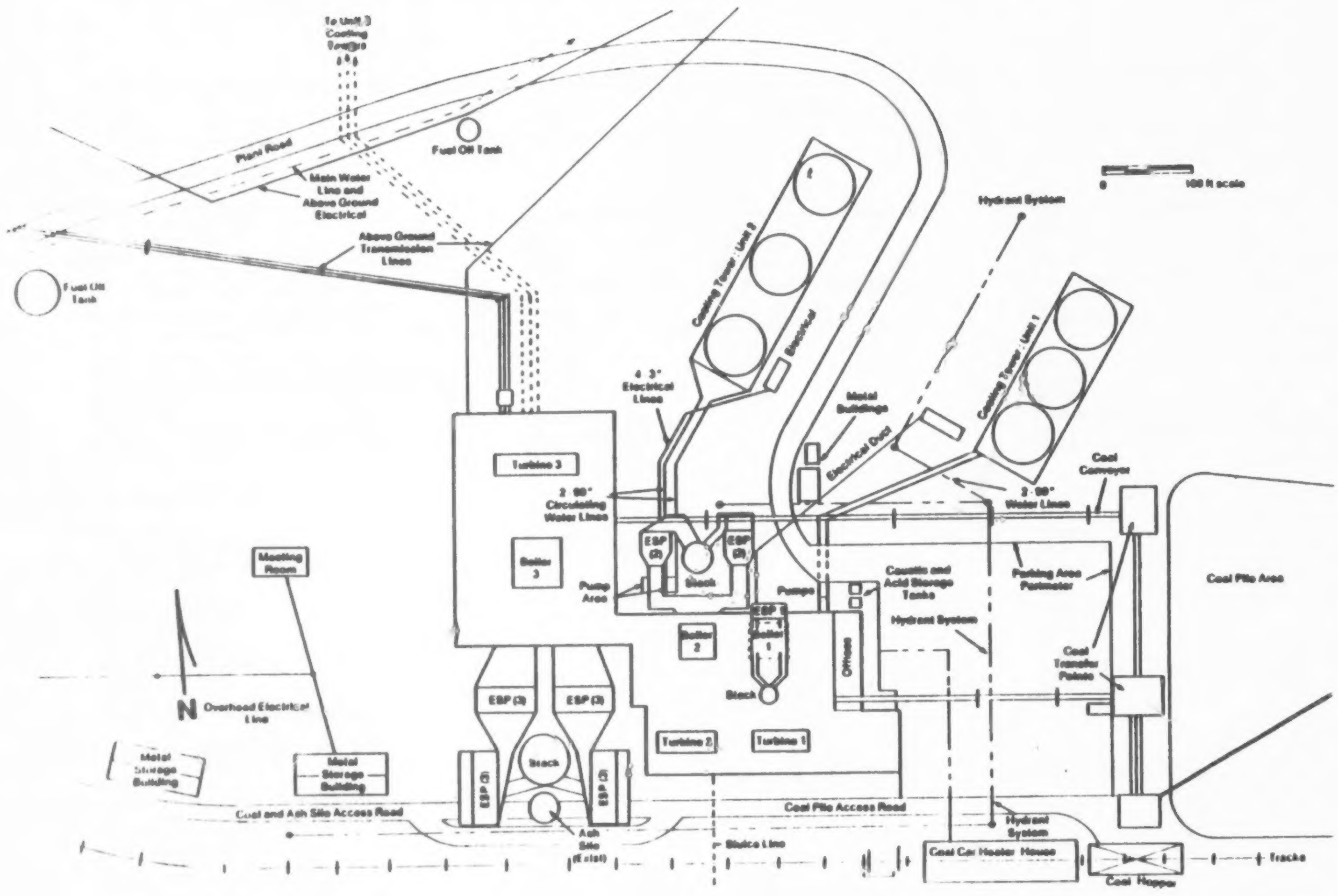

Figure 8-1. Brown Plant plot plan.

TABLE 8-1. KEY DESIGN AND OPERATIONAL DATA FOR BROWN PLANT

Item	Boiler 1	Boiler 2	Boiler 3
BOILER AND STACK DATA			
Net generating capacity (MW)	100	156	403
Boiler manufacturer	Babcock and Wilcox	Combustion Engineering	Combustion Engineering
Installation date	1957	1963	1971
Capacity factor (10 year projected)	50	65	65
Heat rate (Btu/kW-hr)	11,227	10,390	10,329
Boiler type/firing type/bottom type	P.C./front wall/dry	P.C./tangential/dry	P.C./tangential/dry
Boiler dimensions, (ft, D x W x H[a])	33 x 21 x 51	42 x 27 x 75	52 x 41 x 92
Burner type/number of burners (# EL x #/EL)	Circular/4x4	Tangential/4x4	Tangential/4x5
Burner spacing (vert x horiz, ft)	6.5 x --[b]	4.7 x --[b]	5.6 x --[b]
Burner zone heat release rate (Btu/hr-ft^2)	287,000	216,000	376,000
Design oxygen level (percent O_2)/excess air	4.4/25	3.7/20	3.7/20
Draft type	FD/ID	FD/ID	FD/ID
Flue gas flow rate (1000 acfm @ °F)	430 @ 296°F	605 @ 301°F	1750 @ 289°F
Stack size (height x diameter, feet)	345 x 12.7 (assumed)	345 x 14.4 (assumed)	564 x 18.6 (assumed)
Stack liner type	Brick	Steel	Steel
FUEL AND SORBENT DATA			
Coal quality[c]			
Heat content (Btu/lb)	11,965	11,965	11,965
Volatile matter (percent)	28.6	28.6	28.6
Ash (percent)	12.0	12.0	12.0
Moisture (percent)	--[b]	--[b]	--[b]
Sulfur (percent)	1.97	1.97	1.97
Nitrogen (percent)	--[b]	--[b]	--[b]
Coal delivery methods			
Current	Truck	Truck	Truck
Design	Truck/Rail	Truck/Rail	Truck/Rail
Likely method for sorbent delivery	Rail	Rail	Rail
PARTICULATE CONTROL EQUIPMENT DATA			
Type of control New/retrofit control installation	ESP/cold side	ESP/cold side	ESP/cold side
ESP specific collection area ($ft^2/10^3$ acfm)	200	230.4	304.3
Total plate area (10^3 ft^2)	88.8	139.3	266.3
Emission standards (lb/10^6 Btu)	0.254	0.162	0.254
ESP Outlet emissions (lb/10^6 Btu)[d]	0.250	0.160	0.250
Design coal sulfur (percent)	3.1	3.6	3.6
Gas conditioning	None	None	None
Tested efficiency/design efficiency	97.9/98.5	99.7/99	99.7/99

(Continued)

TABLE 8-1. (CONTINUED)

Item	Boiler 1	Boiler 2	Boiler 3
NITROGEN OXIDE CONTROL EQUIPMENT DATA			
NO_x control equipment	None	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA			
SO_2 control equipment	None	None	None
SOLID WASTE DISPOSAL DATA			
Ash transport system type			
Boiler bottom ash	Wet sluice	Wet sluice	Wet sluice
Fly ash	Wet or dry	Wet or dry	Wet or dry
Ash disposal method	Pond/sell	Pond/sell	Pond/sell
Existing pond capacity	5-8 years	5-8 years	5-8 years
Estimated distance to off-site waste disposal	5 miles	5 miles	5 miles

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual rate.

by the same conveyor located on the north end of the parking lot. A separate conveyor is used for unit 3. Coal is fed to the pulverizer feed bins (1 for each unit) which hold a 10-12 hour supply of coal. Currently, there is no coal washing, cleaning, or blending done at the plant. Coal is received by the plant on a two shift per day basis (none on weekends).

Particulate emissions from all three boilers are controlled with ESPs; each is served by a separate stack. The unit 1 ESP is located on top of the unit 1 powerhouse and is served by a roof mounted stack located close by. This ESP has a specific collection plate area of 200 $ft^2/10^3$ acfm and its performance is characterized as marginal by plant personnel (tested efficiency is 97.9 percent). The unit 3 ESP was upgraded with additional plate area in the 1970's and now has an SCA of 304. The tested current efficiency of both units 2 and 3 is 99.7. Both ESPs currently perform well according to plant personnel and can comply with existing particulate emission standards.

Ash from the boilers, economizers, and ESPs for units 1, 2, and 3 is sluiced to the ash pond located just southwest of unit 3 (right across the tracks). This pond is an 80 acre site and is close to being filled to capacity (only 5-8 years of life remain). An additional 15 to 20 acres of capacity could be developed adjacent to the existing pond (just east of the pond); also, land may be available which could be purchased for this purpose. Various options are currently being considered by Kentucky Utilities.

Ash from the ESPs for all 3 units can also be conveyed dry to a 1,000 ton fly ash silo located near unit 3. Ash from this silo is sold for cement manufacturing. Plant personnel indicated that the dry ash removal systems for all ESPs do not have sufficient capacity for full-time operation. Also, if the dry ash contains sorbent material, the plant may lose revenue in being unable to sell the dry waste for cement manufacturing and this source of revenue may be lost. These revenue losses were not considered in this study.

8.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

This section presents cost and performance estimates for the retrofit of commercial SO_2 control technologies at Brown Station. The following technologies were examined: lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching, and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates developed.

8.2.1 Lime/Limestone and Lime Spray Drying FGD

8.2.1.1 Control Cases Evaluated--

Table 8-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. Two basic SO_2 control configurations were considered: (1) separate control systems for each unit, and (2) a low capital cost system which would have a common control system shared by multiple units. Units 1 and 2 are co-located and, as such, are well suited for installation of a shared SO_2 control system. Unit 3's equipment layout is the reverse of units 1 and 2 and, as such, it is not practical to share SO_2 controls with these units. Thus, control system sharing was considered for units 1 and 2 only.

For LSD FGD systems, two cases were considered: one in which the existing ESPs are reused to collect the fly ash and spray drier solids, and one in which new baghouses are installed. It is unlikely that the unit 1 ESP could handle the increased loading associated with LSD FGD. The addition of plate area at the ESPs would be difficult due to limited access space (the ESP is roof mounted near the edge of the building). Therefore, reuse of the existing ESP for unit 1 was not considered a viable option and only the new baghouse case was evaluated. Both the ESP reuse case and the new baghouse case were evaluated for units 2 and 3.

SO_2 removal efficiency for L/LS FGD is assumed to be 90 percent. Removal efficiencies for LSD FGD were estimated to be 85-86 percent if a new baghouse is used and 72-76 percent if the existing ESP is reused.

TABLE 8-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR BROWN PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	1.97	5,700
Boiler 2	90	1.97	11,600
Boiler 3	90	1.97	30,000
LSD FGD (reuse ESP)			
Boiler 2	76	1.97	9,800
Boiler 3	72	1.97	24,000
LSD FGD (new baghouse)			
Boiler 1	86	1.97	5,500
Boiler 2	86	1.97	11,200
Boiler 3	85	1.97	28,400
LOW COST CONTROLS			
Boilers 1 and 2	90	1.97	18,100
Boiler 3	90	1.97	31,200

8.2.1.2 Layout of Equipment and Design Basis--

An important consideration in the development of retrofit factors and costs is the placement of the major components of the SO_2 control systems at the site. Site-specific access/congestion and other factors can complicate the placement of control equipment and thus impact retrofit cost. For each L/LS FGD and LSD FGD case, a simplified plant drawing was prepared to evaluate the placement of key components of each SO_2 control system, such as absorbers, spray dryers, ductwork, baghouses, clarifiers/vacuum filters, sorbent receiving/storage, sorbent preparation, and waste storage systems. This layout was then used to develop retrofit difficulty factors and other retrofit cost considerations.

The first step in developing the conceptual designs was to estimate the approximate size of the SO_2 control system components listed above. All systems were sized based on the maximum power output for each unit. Also, for sizing sorbent receiving and storage equipment, lime was assumed to be the sorbent of choice for L/LS FGD. Specific drawings prepared for individual control cases are listed below.

Figure Number	FGD Control Case Description
8-2	Separate L/LS FGD systems for units 1, 2, and 3
8-3	Combined L/LS FGD system for units 1 and 2
8-4	Separate LSD FGD systems for units 1, 2, and 3 with new baghouses
8-5	Separate LSD FGD on units 2 and 3 with reuse of existing ESPs

These drawings are to approximate scale, but are not intended to represent the accuracy and detail associated with an engineering drawing. They were prepared from drawings supplied by the plant, sketches and measurements made during the plant visit, and photographs taken during the plant visit. These drawings were also reviewed by plant personnel.

The majority of the control equipment was located in open areas to the southeast of cooling tower 2 for the unit 1 and 2 control systems and to the west of unit 3 for the unit 3 control system. Control equipment for unit 3 was not located south of the tracks (directly south of the unit 3 ESP) because of the likelihood this area will be used for future ash disposal. For unit 3, the relatively large open area allows a somewhat conventional control system design to be used.

8.2.1.3 Scope Adjustments--

In order to retrofit FGD control systems at the Brown plant, some existing equipment must be modified. Costs for modifications which are not included in IAPCS are referred to as scope adjustments or cost adders and are summarized in table 8-3 for all FGD cases evaluated.

Although the ash handling system for all three units can currently operate in the dry mode, plant personnel indicated that insufficient capacity exists for all three systems to operate in a dry mode on a continuous basis. Thus, the cost for installing a new dry ash system was included for all three units for the L/LS FGD and LSD FGD (ESP reuse) cases.

The analysis assumed sorbent would be received at the plant by rail. The rail spur shown in figures 8-2 through 8-5 is actually 3 to 4 different rails which are used for coal unloading, sampling, and short-term storage. Because sorbent unloading activities would interfere with coal unloading operations, the cost of a new 400-foot rail spur was added to support sorbent unloading operations. The cost for new rails was assumed to be one million dollars per mile (ConRail, 1986).

The costs for balanced draft controls, building/electrical/duct demolition, and stack relining were based on EPRI guidelines. The cost to relocate buildings and plant roads was accounted for as a general facilities cost. For all cases, general facilities factors of 10 to 15 percent were used for units 1 and 2, and 5 percent for unit 3. For the LSD with the new baghouse cases, IAPCS adds the cost of the baghouse as a separate line item.

TABLE 8-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR BROWN PLANT

Scope Adjustment	Description[a]
o New stack	A new stack was added (7.04 $/kW) when reuse of existing stacks is more expensive than a new stack (LSD FGD on Unit 1).
o Balanced draft controls	Balanced draft controls were required with all SO_2 controls. ($1.20/kW)
o Building/duct work/ electrical demolition and relocation	When these items interfere with the placement of equipment, demolition and relocation costs are added. ($0.13 - 0.87/kW)
o Ash Removal/Conveyance Modification	The ESP ash discharge systems for units 1, 2, and 3 are upgraded for all L/LS FGD and LSD FGD (ESP reuse) cases. ($8.28 - 9.57/Kw).
o Stack Relining	The existing steel stacks were relined to prevent corrosion for all L/LS FGD systems ($40/$ft^2$).
o New Rails	New rail spur is installed to allow sorbent unloading operations to be separate from coal unloading operations.

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

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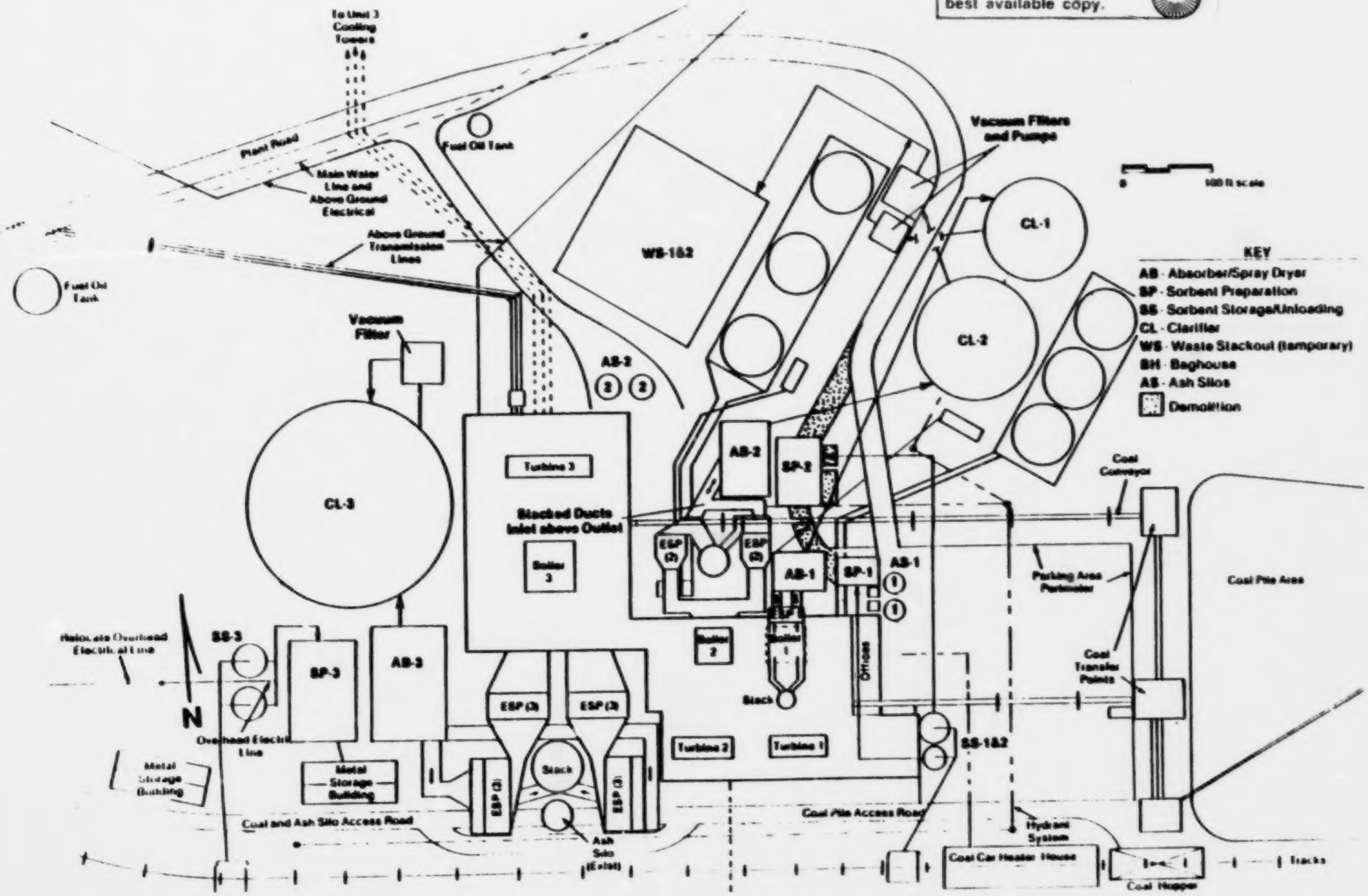

Figure 8-2. Brown Plant lime/limestone FGD for units 1, 2, and 3.

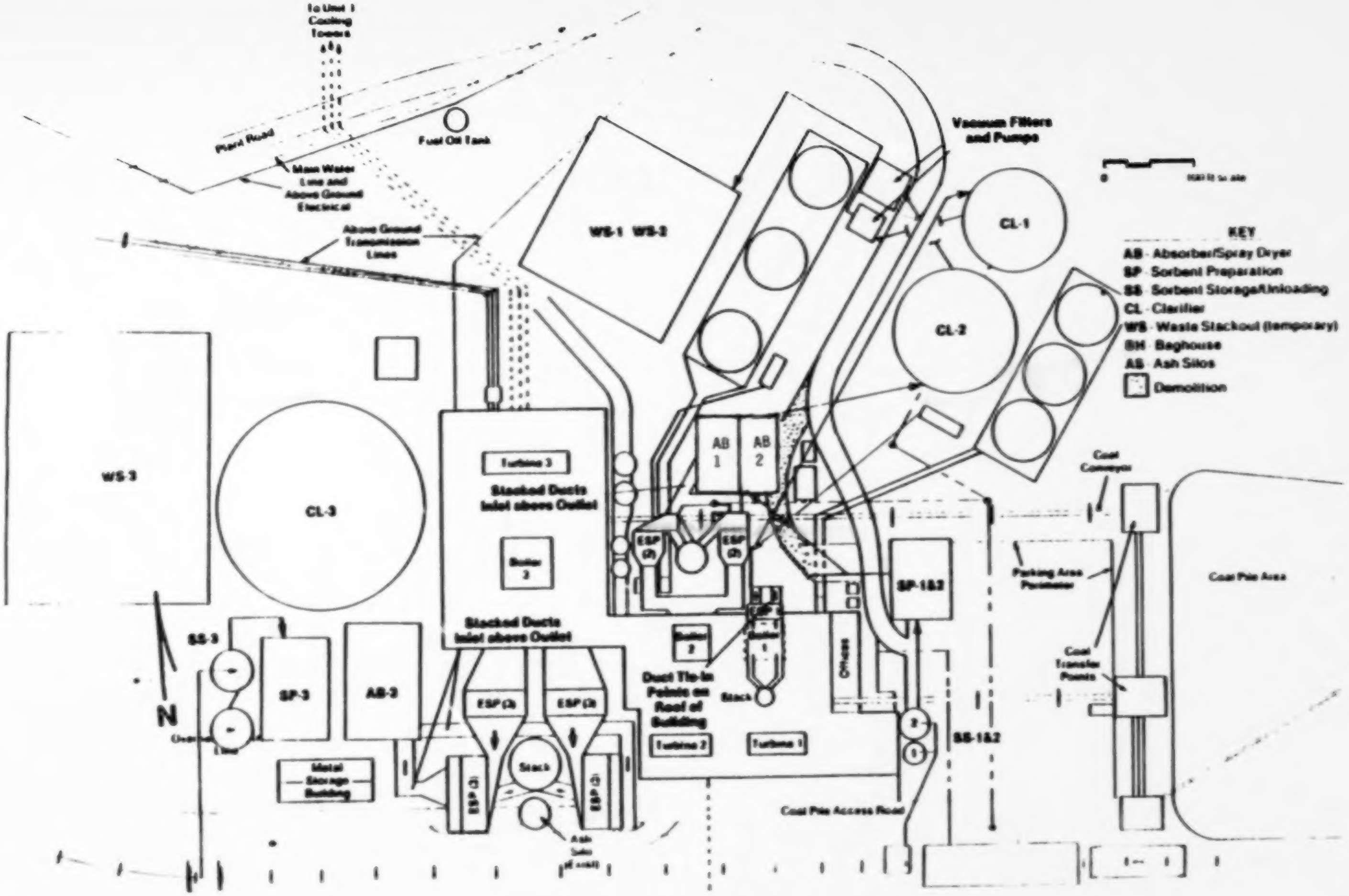

Figure 8-3. Brown Plant lime/limestone for FGD systems for unit 3 and combined system for units 1 and 2.

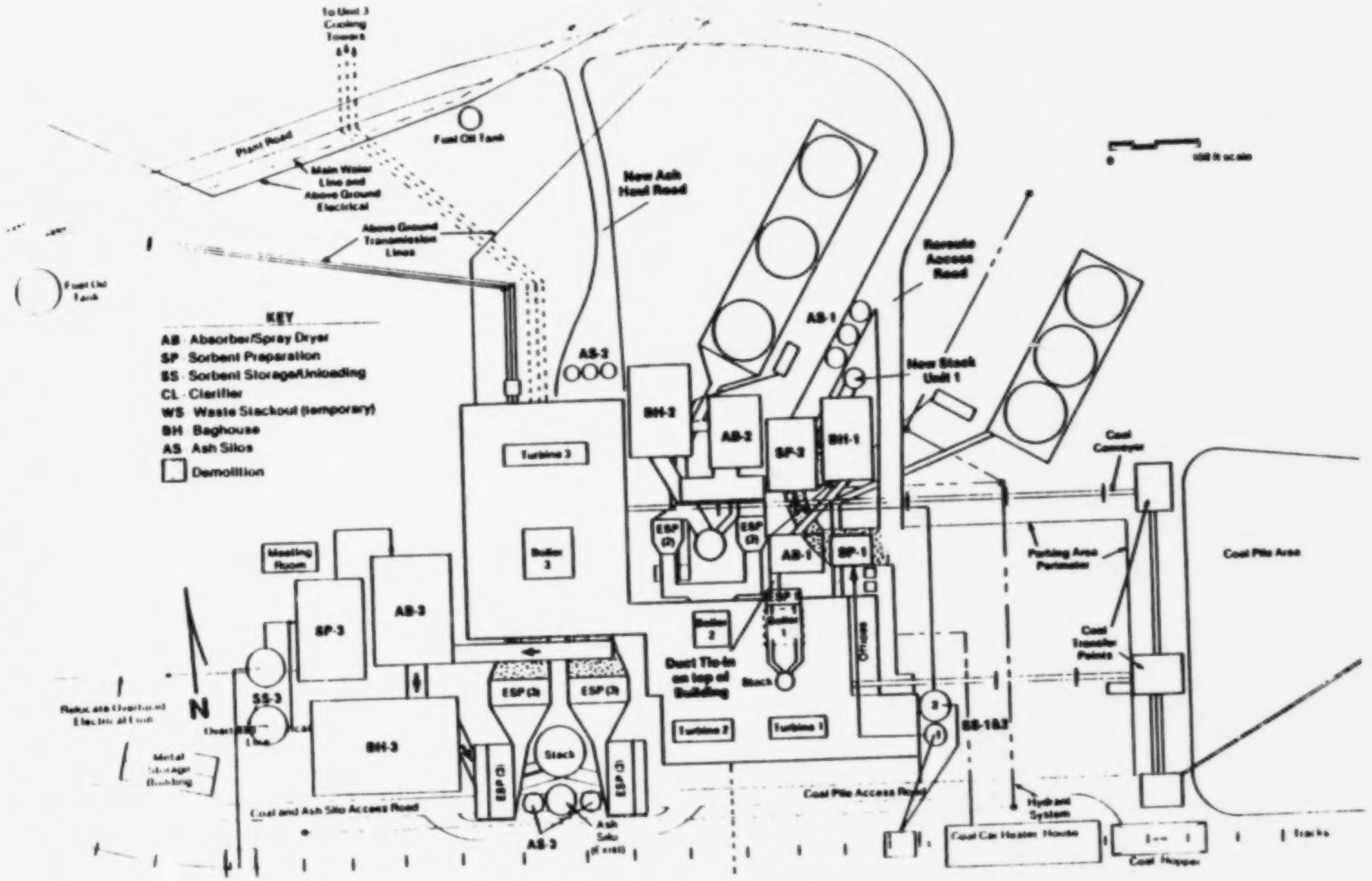

Figure 8-4. Brown Plant lime spray drying on all units with new baghouse particulate control.

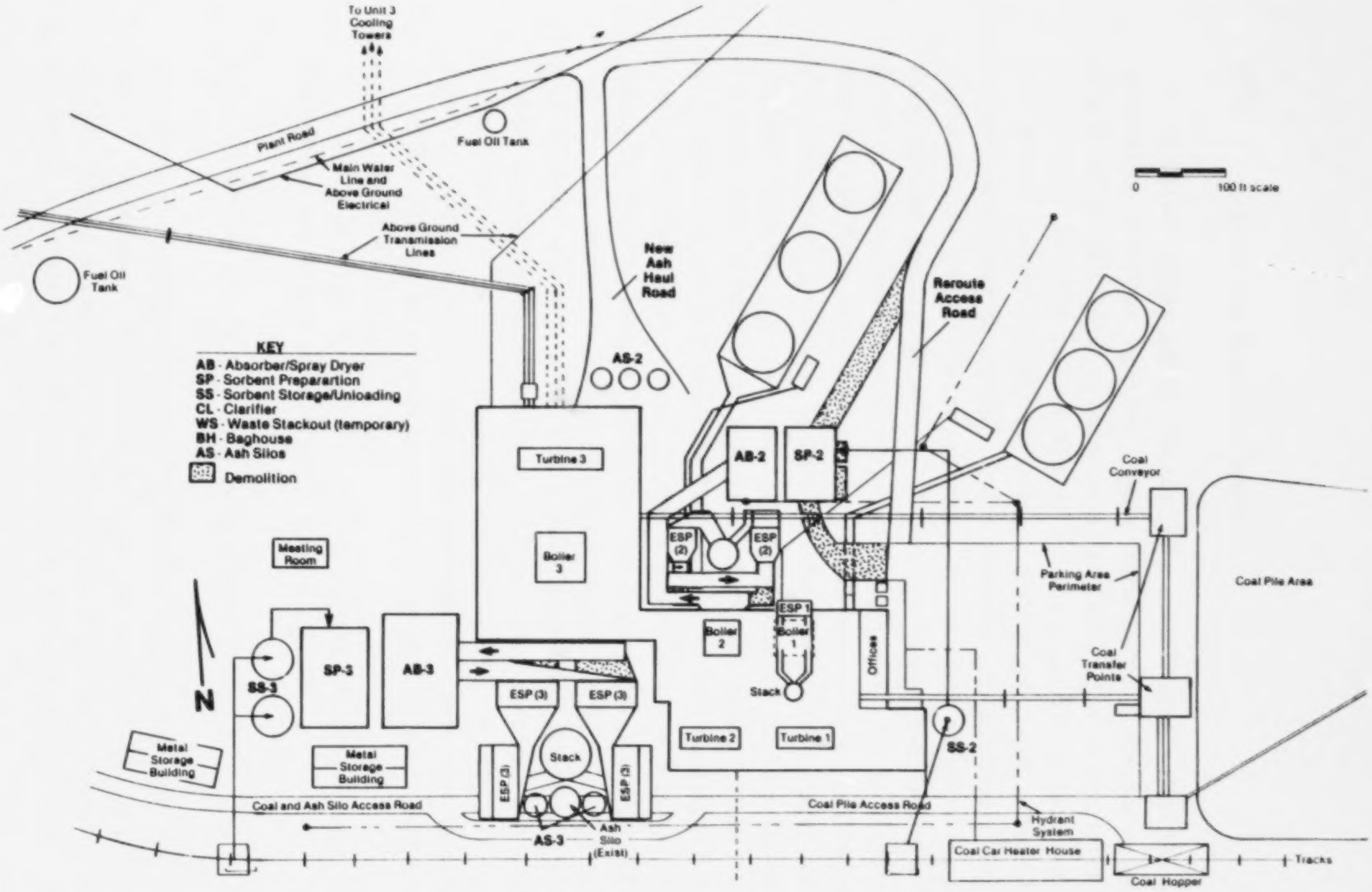

Figure 8-5. Brown Plant separate LSD on units 2 and 3 with reuse of existing ESPs.

8.2.1.4 Location and Retrofit Factors--

Location factors adjust the cost of a control system from the base case location to any other location. These factors account for the site-specific effects of seismic zone, climate, material cost, labor productivity, and soil conditions. Retrofit factors account for costs associated with the site-specific difficulty of retrofitting control equipment. These factors include underground obstructions, site accessibility and congestion, distance to the control system (tie-in ductwork), and distance to the waste processing equipment and preparation area. Tables 8-4 through 8-6 summarize the retrofit factors used for all of the cases examined. The location factors used for the Brown plant result from the higher than base location costs associated with (1) shallow bedrock (3-4 feet below the surface) and (2) regional labor and materials costs (1.06 relative to the base location). Key distances used in developing retrofit factors are shown in table 8-7.

Tables 8-4 and 8-5 summarize the retrofit factors developed for the FGD cases where individual control systems are applied to each unit. The aggregate retrofit factors for units 1 and 2 are generally higher than for unit 3. The primary reasons for these differences are the significant amount of free space adjacent to the unit 3 powerhouse which allows fairly standard control system configurations (i.e. similar to new construction) and reduces access and congestion related costs compared to units 1 and 2. Cooling towers, circulating water lines, the overhead coal conveyance system, and the powerhouse structures contributed to medium to high site access/congestion factors for units 1 and 2.

Table 8-6 lists the retrofit factors for the low capital cost case where FGD systems are shared between units 1 and 2.

8.2.1.5 Overall Retrofit Factors and Costs--

Table 8-8 presents the overall retrofit factors and costs for all FGD cases. The range of costs shown for L/LS FGD and reflects the different process options evaluated: conventional and adipic acid enhanced limestone FGD and conventional and MgO enhanced lime FGD. The LSD FGD costs include

TABLE 8-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED AT BROWN PLANT

Item	Units 1-2 LOCF[a]	Boiler #1 UGOF[b]	Boiler #1 ACCF[c]	Boiler #1 DISF[d]	Boiler #1 AGGF[e]	Boiler #2 UGOF[b]	Boiler #2 ACCF[c]	Boiler #2 DISF[d]	Boiler #2 AGGF[e]	Unit 3 LOCF[a]	Boiler #3 UGOF[b]	Boiler #3 ACCF[c]	Boiler #3 DISF[d]	Boiler #3 AGGF[e]
PROCESS EQUIPMENT														
Reagent Feed	1.08	1.01	1.25	1.00	1.26	1.01	1.05	1.00	1.06	1.12	1.00	1.02	1.00	1.02
SO_2 Removal	1.06	1.06	1.50	1.00	1.59	1.06	1.30	1.00	1.38	1.07	1.00	1.10	1.00	1.10
Flue Gas Handling	1.09	1.06	1.10	1.19	1.39	1.06	1.50	1.04	1.65	1.13	1.06	1.50	1.20	1.91
Waste Handling	1.07	1.14	1.02	1.02	1.19	1.14	1.15	1.01	1.32	1.10	1.00	1.02	1.00	1.01
General Support Equipment	1.08	1.12	1.24	1.00	1.39	1.12	1.24	1.00	1.39	1.12	1.00	1.02	1.00	1.02
SCOPE ADJUSTMENTS														
Wet to Dry Ash System	1.08	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
New Chimney	N/A[f]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES														
Engineering - %			12				12					10		
General Facilities - %			15				10					5		

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 8-7 for distance assumptions.
[e] AGGF = Aggregate Factor.
[f] N/A = Not applicable.

TABLE 8-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR BROWN PLANT

	RETROFIT FACTORS													
		Boiler #1				Boiler #2					Boiler #3			
Item	Units 1-2 LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	Unit 3 LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT														
Reagent Feed	1.15	1.01	1.25	1.00	1.26	1.06	1.05	1.00	1.11	1.31	1.00	1.02	1.00	1.02
SO_2 Removal	1.09	1.06	1.50	1.00	1.59	1.06	1.30	1.00	1.38	1.14	1.00	1.10	1.00	1.10
Flue Gas Handling	1.14	1.06	1.30	1.13	1.55	1.06	1.50	1.45	2.31[f]	1.28	1.06	1.10	1.21	1.41[f]
General Support Equipment	1.14	1.12	1.24	1.00	1.39	1.12	1.24	1.00	1.39	1.29	1.00	1.02	1.00	1.02
SCOPE ADJUSTMENTS														
Ash Silo	N/A[g]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
New Chimney	1.08	1.00	1.02	1.00	1.02	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Baghouse	1.09	1.00	1.10	1.00	1.10	1.00	1.30	1.00	1.30	1.09	1.00	1.10	1.00	1.10
ESP Plate Area Addition	1.09	N/A	N/A	N/A	N/A	1.00	1.10	1.00	1.10	1.09	1.00	1.30	1.00	1.30
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES														
Engineering - %				12				12					10	
General Facilities - %				15				10					5	

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 8-7 for distance assumptions used.
[e] AGGF = Aggregate Factor.
[f] Based on reusing EPS. If a new baghouse is used, the aggregate factor is 1.75 for unit 2 and 1.31 for unit 3.
[g] N/A = Not applicable.

TABLE 8-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES AT BROWN PLANT

		RETROFIT FACTORS								
		Boiler #1					Boiler #3			
Item	Units 1-2 LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	Unit 3 LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT										
Reagent Feed	1.08	1.01	1.25	1.00	1.26	1.12	1.00	1.02	1.00	1.02
SO_2 Removal	1.06	1.06	1.50	1.00	1.59	1.07	1.00	1.10	1.00	1.10
Flue Gas Handling	1.09	1.06	1.10	1.19	1.39	1.13	1.06	1.50	1.20	1.91
Waste Handling	1.07	1.14	1.02	1.02	1.19	1.10	1.00	1.02	1.00	1.01
General Support Equipment	1.08	1.12	1.24	1.00	1.39	1.12	1.00	1.02	1.00	1.02

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 8-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 8-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR BROWN PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
INDIVIDUAL CONTROLS				
L/LS FGD				
Boiler 1	171	171	100	380
Boiler 2	123	62	100	220
Boiler 3	176	176	100	20
LSD FGD (new baghouse)				
Boiler 1	175	100	100	N/A[c]
Boiler 2	135	115	100	N/A
Boiler 3	180	90	100	N/A
LSD FGD (reuse ESP)				
Boiler 2	300	300	100	N/A
Boiler 3	180	180	100	N/A
LOW COST CONTROLS				
L/LS FGD				
Boilers 1-2	170	170	100	300
Boiler 3	176	176	100	20

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

TABLE 8-8. L/LS AND LSD FGD COSTS FOR BROWN PLANT
(August 1987 Dollars)

Case Description	Overall Retrofit Factor	IAPCS Retrofit Costs[a]		
		Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS[a]				
L/LS FGD				
Boiler 1[a]	1.70	376.6-460.0	2,306-2,697	30.2-35.3
Boiler 2[a]	1.60	283.6-347.4	1,526-1,726	20.0-22.6
Boiler 3[a]	1.41	175.1-213.6	1,035-1,178	13.5-15.4
LSD FGD (reuse ESP)				
Boiler 2	1.69[b]	219.6	1,194	13.2
Boiler 3	1.25[b]	136.4	814	8.5
LSD FGD (new baghouse)				
Boiler 1	2.00[c]	345.6	2,016	25.3
Boiler 2	1.82[c]	300.3	1,354	17.0
Boiler 3	1.50[c]	221.6	1,019	12.6
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1 and 2	1.65	179.8	989	13.4
LSD FGD				
Boiler 3	1.41	143.8	782	10.6

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] No plate area increase needed.

[c] Includes impact of new baghouse.

TABLE 8-8. L/LS AND LSD FGD COSTS FOR BROWN PLANT (August 1987 Dollars)

Case Description	Overall Retrofit Factor	IAPCS Retrofit Costs[a]		
		Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS[a]				
L/LS FGD				
Boiler 1[a]	1.70	376.6-460.0	2,306-2,697	30.2-35.3
Boiler 2[a]	1.60	283.6-347.4	1,526-1,726	20.0-22.6
Boiler 3[a]	1.41	175.1-213.6	1,035-1,178	13.5-15.4
LSD FGD (reuse ESP)				
Boiler 2	1.69[b]	219.6	1,194	13.2
Boiler 3	1.25[b]	136.4	814	8.5
LSD FGD (new baghouse)				
Boiler 1	2.00[c]	345.6	2,016	25.3
Boiler 2	1.82[c]	300.3	1,354	17.0
Boiler 3	1.50[c]	221.6	1,019	12.6
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1 and 2	1.65	179.8	989	13.4
LSD FGD				
Boiler 3	1.41	143.8	782	10.6

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] No plate area increase needed.

[c] Includes impact of new baghouse.

(1) upgrading the ESPs and ash handling systems and (2) installing new baghouses to handle the additional particulate loading.

Figures 8-6 and 8-7 illustrate the plant level costs for installing retrofit L/LS FGD and LSD FGD. Figure 8-6 shows the cost of lime FGD. Unit 3 has the lowest cost per ton for both L/LS and LSD FGD, followed by unit 2, and then unit 1. The data point labeled low cost shows the impact of economies-of-scale when combining process areas and scrubber optimization by eliminating the spare towers and maximizing the towers' size and use of adipic acid additives.

Use of L/LS FGD to all units is projected to reduce plant-wide SO_2 emissions by 47,300 tons per year assuming 90 percent emission reduction. For application of LSD FGD, the estimated emission reduction for units 2 and 3 is 33,800 tons per year if the ESPs are upgraded (unit 1 is not controlled in this case) and 45,100 tons per year if replacement baghouses are installed (includes all 3 units).

8.2.2 Coal Switching/Blending

Table 8-9 presents the coal quality data used to evaluate the impact of coal switching on Brown Station units 2 and 3. The unit 1 ESP is roof mounted and the addition of plate area would be difficult. Therefore, coal switching/blending and physical coal cleaning were not considered for unit 1. The switch coal is low-sulfur Kentucky coal having a sulfur content of 1 percent. Table 8-9 also presents the ESP plate area requirements needed for the switch coal.

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3

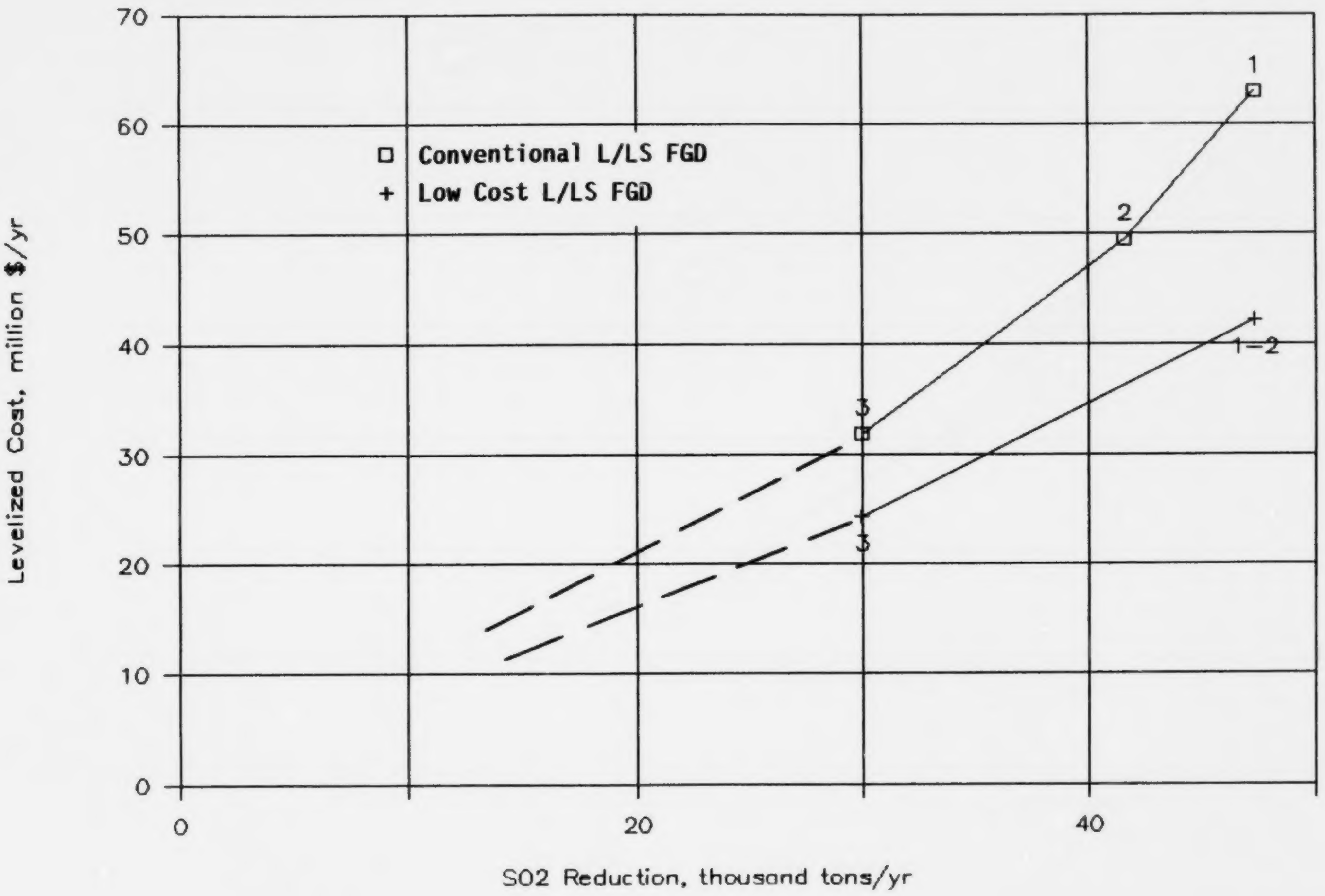

Figure 8-6. Brown Plant L/LS cost versus SO_2 reduction.

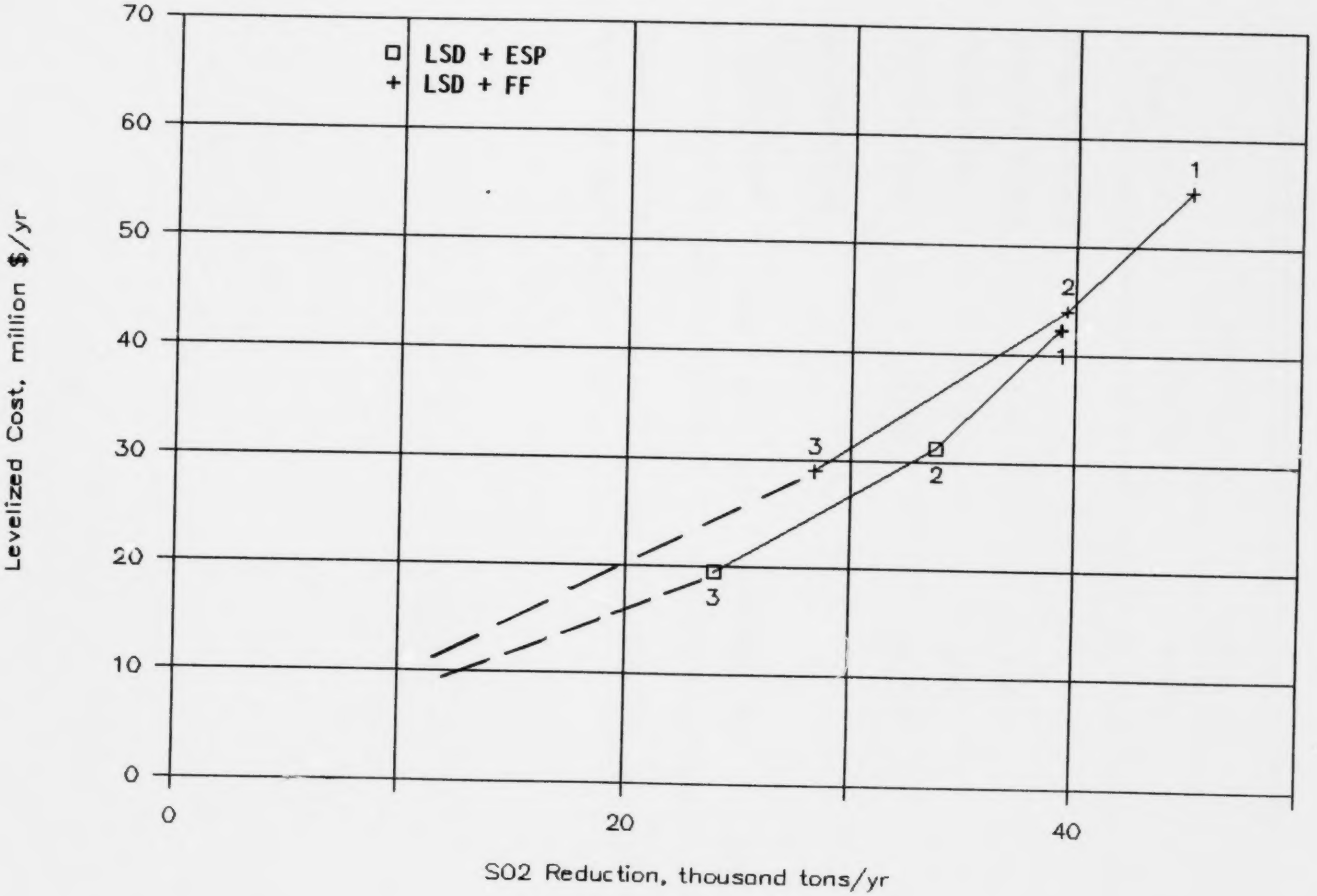

Figure 8-7. Brown Plant lime spray dryer FGD cost versus SO_2 reduction.

TABLE 8-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR BROWN PLANT

Item	Existing Coal			Switch Coal			Cleaned Coal		
	Boiler 1	Boiler 2	Boiler 3	Boiler 1	Boiler 2	Boiler 3	Boiler 1	Boiler 2	Boiler 3
COAL PARAMETERS									
Percent Sulfur		2.0			1.0			0.93	
Percent Ash		12.0			10.5			4.6	
Btu Per Pound		11,965			12,100			13,000	
ESP PARAMETERS									
Existing/ Needed SCA[a]	200	230	304	N/A[b]	269	266	N/A	269	266

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

[b] N/A = Not applicable.

conditioning was assumed to reduce the needed plate area up to 25 percent. For boiler 2 with SO_3 conditioning, a 17 percent increase in the existing ESPs would be needed for low-sulfur coal service. However, because the benefits of SO_3 conditioning are highly variable, the predicted cost for ESP plate area increase should be viewed as a minimum estimate. For boiler 3 no additional plate area would be required.

Figure 8-8 presents the plant level cost and emission reduction for switching to a low sulfur coal. Curves were generated to show the impact of different coal fuel price differentials. The lower curve is based on a levelized 1985 fuel price differential of $8.26 per ton between the existing coal and an eastern Kentucky low sulfur coal. The upper curves shows the impact of additional fuel price differentials of $15 per ton over the 1985 fuel price differential. Approximately 23,400 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.5 pound per million Btu SO_2 emission rate. The costs associated with each boiler for the range of fuel cost differential (FCD) including SO_3 conditioning are shown in table 8-10.

TABLE 8-10. COAL SWITCHING COSTS FOR BROWN PLANT
(August 1987 Dollars)

		@ $8.26/ton FCD		@ $23.55/ton FCD	
Boiler	SO_2 Reduction (tons/year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
2	6,500	838	6.2	2,117	15.6
3	16,900	777	5.7	2,056	15.1

It is not anticipated that additional coal handling facilities would be necessary, but if separate coal storage and/or coal blending is required, additional facilities would be needed. However, the cost of these coal

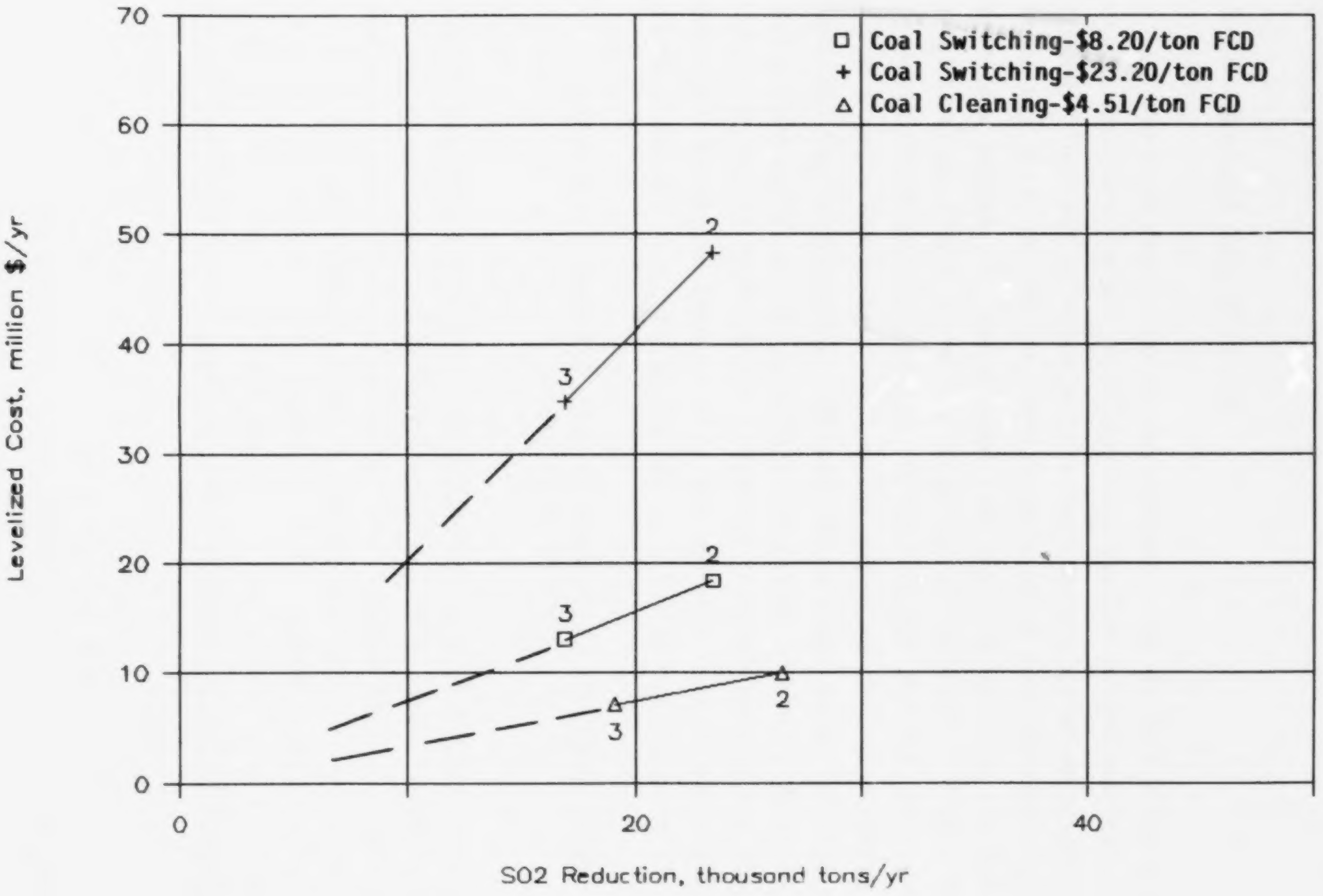

Figure 8-8. Brown Plant coal switching/cleaning costs versus SO_2 reduction.

handling facilities is likely to be small relative to the fuel cost differential.

8.2.3 Physical Coal Cleaning

Physical coal cleaning was evaluated for boilers 2 and 3 using coal characteristics for a high-sulfur coal similar to the one that currently is burned. The cost of cleaning this coal was estimated using the IAPCS model which has cost for cleaning twelve coals which were developed using a model developed by TVA. It was assumed that the coal would be cleaned at the mine, and no refuse disposal would be required at the plant. Figure 8-8 also presents the results of the cost model runs for physical coal cleaning at the Brown plant. These costs include the estimated cost of cleaning ($4.51 per ton) and SO_3 conditioning. However, these costs do not include reduced pulverizer costs, system modifications needed to handle cleaned coal, or the impact on boiler performance. Cleaning the coal reduces the plant SO_2 emissions by 26,500 tons/yr at an average unit cost of $375 to $389 per ton of SO_2 removed. Cost estimates for each boiler are shown in table 8-11.

TABLE 8-11. PHYSICAL COAL CLEANING COSTS FOR BROWN PLANT
(August 1987 Dollars)

Boiler	SO_2 Reductions (tons/year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
2	7,400	389	3.2
3	19,100	375	3.1

8.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data. For the Brown plant the following control technologies were considered: furnace sorbent injection (FSI), duct spray drying (DSD), and retrofit applicability of fluidized bed combustion (FBC) or coal gasification (CG).

8.3.1 Sorbent Injection Technologies

This section discusses retrofit issues and cost/performance estimates for furnace sorbent injection (FSI) and duct spray drying (DSD) SO_2 control technologies. These two technologies are being developed for retrofit applications but have not been demonstrated on commercial utility boilers. As a result, the cost/performance estimates for FSI and DSD have a high degree of uncertainty due to the lack of commercial scale data.

Retrofit factors and scope adder costs developed for these technologies at the Brown plant primarily focus on scope adders which are not included in the base capital cost assumptions. This included retrofit difficulty factors for particulate collector upgrading and scope adder costs for demolition and relocation of existing equipment and buildings, construction of a new chimney, and conversion of wet fly ash handling systems to dry handing and storage. Basic assumptions and cost adjustments made for FSI and DSD at Brown plant are identified in table 8-12. General layout of sorbent injection equipment is shown in figure 8-9.

8.3.1.1 Furnace Sorbent Injection--

Since the ESP for unit 1 cannot be practically upgraded, FSI was evaluated for units 2 and 3 only. The equipment layout is similar as shown

TABLE 8-12. SCOPE ADJUSTMENTS FOR FSI AND DSD AT BROWN PLANT

Item	Boiler 1	Boiler 2	Boiler 3
BASIC ASSUMPTIONS			
Approximate access/congestion rank	Medium	Medium	Medium
Can the existing ESP be upgraded?	No	Yes	Yes
Was a new baghouse evaluated for DSD?	Yes	Yes	Yes
Distance to final waste disposal (miles)	5	5	5
SCOPE ADDERS			
Install dry ash handling system[a]	N/A[b]	Yes	Yes
New Stack	Yes	No	No
Additional duct work (ft)[c]	330	130	270
Duct demolition length (ft)[c]	50	110	100
Building demolition area (ft^2)[c]	910	0	4,533
ADDER COSTS AND RETROFIT FACTOR SUMMARY			
Scope adder cost for new baghouse (10^3 \$)[d]	3,447	1,254	3,157
Scope adder costs for ESP reuse (10^3 \$)[d]	N/A	1,502	3,473
Baghouse retrofit difficulty factor	1.10	1.30	1.10
ESP upgrade retrofit difficulty factor (for plate area addition)	N/A	1.10	1.30

[a] Not applicable when a new baghouse is installed.

[b] N/A = Not applicable.

[c] Not applicable when the existing ESP is used.

[d] June 1985 dollars.

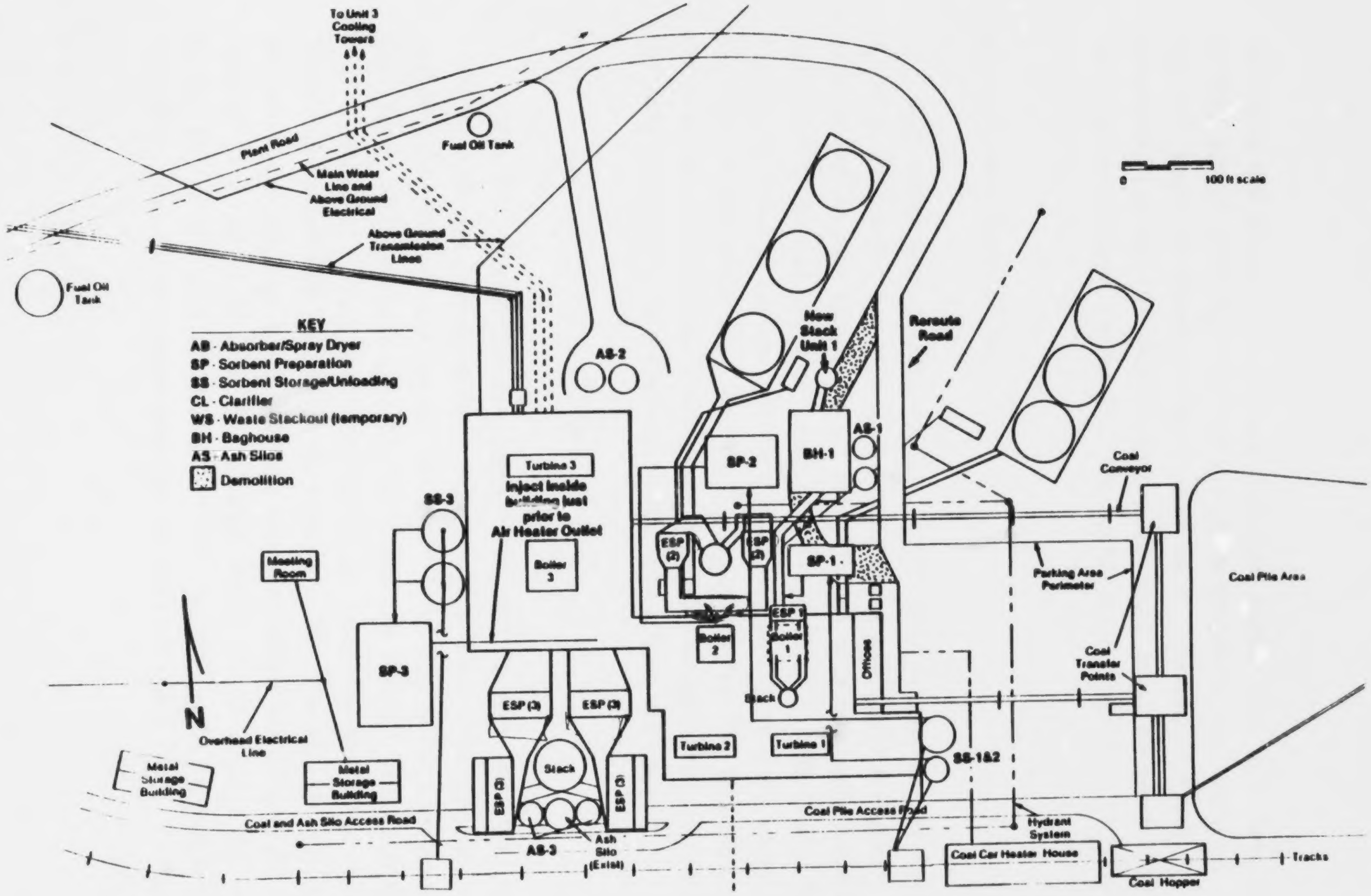

Figure 8-9. Brown Plant duct sorbent injection for units 1, 2, and 3.

in Figure 8-9 except that furnace injectors rather than duct injectors would be used and an area for slurry preparation system is not required. Instead, day bins would be located close to each unit. Key retrofit cost considerations for FSI include adding ESP plate area, conversion of the ash handling system from wet to dry, and addition of a new rail line for sorbent delivery.

8.3.1.2 Duct Spray Drying--

Duct spray drying (DSD) using a lime slurry sorbent was evaluated for units 1, 2, and 3. For unit 1, a new baghouse and stack are used. For units 2 and 3, both ESP reuse and installation of a new baghouse were evaluated. The new baghouse case for units 2 and 3 is not shown, but is similar to the LSD system configuration shown in Figure 8-4 (except the absorber is not required). Key cost adjustments for DSD include the particulate collector and stack, duct demolition, additional ductwork, building demolition, and new rail lines for sorbent delivery.

8.3.1.3 Overall Retrofit Factors and Costs--

Table 8-13 summarizes the overall retrofit factors and costs for the sorbent injection technologies. Figure 8-10 presents the cost of retrofitting FSI and DSD versus the plant level SO_2 reductions achieved. For duct spray drying, plant-wide SO_2 emissions are reduced by 25,800 tons per year assuming the least cost combination of cases for the three units (fabric filter on unit 1 and reuse ESPs on 2 and 3). For the FSI technology, SO_2 emissions are reduced by 23,200 tons per year under the 50 percent SO_2 removal case and by 32,300 tons per year under the 70 percent SO_2 removal case. FSI is not applied to unit 1 since the ESP cannot be practically upgraded, thus, these reductions are for units 2 and 3 only.

TABLE 8-13. RETROFIT COSTS FOR FSI AND DSD FOR BROWN PLANT
(August 1987 dollars)

Case Description	IAPCS Capital Cost (\$/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost (\$/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50% removal)[a]				
Boiler 2	74.7	7.2	992	6,500
Boiler 3	52.8	5.7	783	16,700
Furnace Injection (70% removal)[b]				
Boiler 2	75.1	7.3	713	9,000
Boiler 3	52.8	5.7	563	23,300
Duct Spray Drying (ESP reuse)				
Boiler 2	62.9	6.6	940	6,200
Boiler 3	42.4	4.4	653	15,300
Duct Spray Drying (new baghouse)				
Boiler 1	218.6	17.8	1,814	4,300
Boiler 2	180.3	11.8	1,201	8,700
Boiler 3	140.0	8.9	921	22,300

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

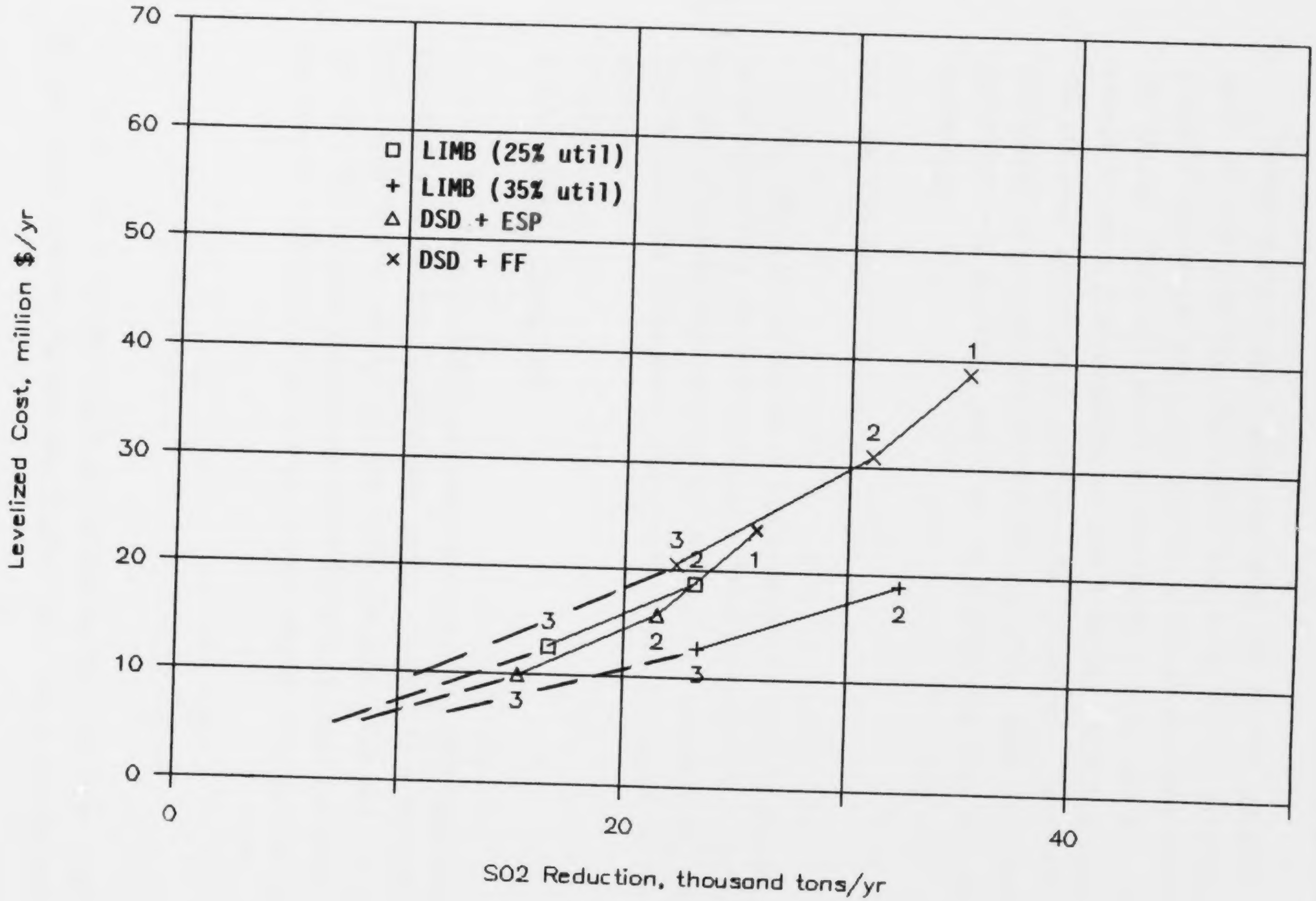

Figure 8-10. Brown Plant FSI/DSD cost versus SO_2 reduction.

8.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG)

Boiler Units 1 and 2 were evaluated for FBC/CG retrofit. Unit 1 is small in size (100 MW), has a good heat rate (11,227 Btu/kWh), has a moderate capacity factor (50 percent), and has a relatively long expected service life (30 years). This unit would be considered a good candidate for FBC/CG retrofit. Unit 2 is moderate in size (156 MW) and has a high capacity factor (65 percent) and expected service life (24 years). This unit would also be considered as a candidate for FBC/CG retrofit. Unit 3, a large size (403 MW) and relatively new unit, would not be a good candidate for this retrofit technology.

8.4 NO_x CONTROL TECHNOLOGIES

NO_x controls evaluated at the Brown plant include low NO_x burners/overfire air and selective catalytic reduction. The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls at the three Brown plant boilers are discussed in the following sections.

8.4.1 Low NO_x Combustion

Low NO_x burners (LNB) and overfire air (OFA) were considered applicable and evaluated for the three boiler units. Unit 1 is a dry bottom, front wall-fired furnace design and LNB was evaluated. For units 2 and 3, which are of a dry bottom, tangential-fired furnace design, overfire air (OFA) was considered. Additional boiler and burner design information is provided in tble 8-1.

8.4.1.1 Low NO_x Burners--

Unit 1 is a 100 MW, front wall-fired boiler. The heat input rate per burner (approximately 80 million Btu/hr) relative to the furnace depth (33 feet) is very low for a wall-fired unit. Therefore, rear wall flame impingement should not be a problem for a LNB retrofit. Because the burner heat input relative to the furnace height above the top burner row is moderate to high, flame impingement on the superheater/reheater tubes should also not be a problem. However, with the narrow furnace and intermediate to low volatility of the coal, there is some potential for carbon burnout problems with a low NO_x burner retrofit. This potential is reflected in the non-volatile fraction of the boiler heat input flux (1.3 million Btu/hr ft^2) relative to the furnace residence time (1.5 seconds) and the upper furnace residence time (0.62 seconds). This concern is supported by the high furnace volumetric heat release rate (35,000 Btu/hr ft^3). No coal slagging problems were identified in unit 1. This may be due, in part, to the intermediate excess air operating level (25 percent).

Considering all the above factors, unit 1 should exhibit intermediate to high NO_x reduction performance with a LNB retrofit. However, because of the slight concern regarding the narrow furnace and low furnace residence times, the LNB retrofit NO_x reduction performance is estimated at 40-50 percent, just below the maximum.

8.4.1.2 Overfire Air--

Unit 2 is a 156 MW, tangential-fired boiler. The burner heat input (approximately 90 million Btu/hr) relative to the distance from the top burner row to the furnace nose (33 feet) is low. This indicates ample room is available above the top burner row for placement of the OFA ports. However, the bulk and upper furnace residence times available for completing combustion are low for a tangential unit, thus increasing the potential for carbon burnout problems and limiting the retrofit OFA system NO_x reduction performance. The degree of flame interaction, based on the burner heat input relative to the vertical burner spacing, though not critical for an OFA retrofit, is low.

For thermal NO_x effects, although not as critical for tangential units, the furnace volumetric heat release rate of 18,000 Btu/hr-ft^3 is considered high; whereas, the burner zone heat release rate of 220,000 Btu/hr-ft^2 is considered to be low. Both these heat release rates would tend to cancel each other and, as a result, will have little effect on NO_x reduction performance. Fuel NO_x effects are unknown due to lack of data on fuel nitrogen and oxygen/nitrogen (O/N) ratios. The plant indicated no significant slagging problems on unit 2. This observation is supported by the intermediate excess air levels (20 percent).

Based on these factors, a retrofit OFA system applied to unit 2 is expected to exhibit an intermediate to high NO_x reduction performance of 20 to 30 percent. This estimate is based on the ability to place OFA ports above the top burner row and on the relatively low heat release rates, but is tempered by the furnace's low residence times which increase the potential for carbon burnout problems.

Unit 3 is a 410 MW, tangential-fired boiler. The burner heat input (approximately 200 million Btu/hr) relative to the distance from the top burner row to the furnace nose (46 feet) is quite high. This suggests the potential for flame impingement on superheater/reheater tubes from the upper burners. In addition, bulk and upper furnace the residence times available for completing combustion are low for a tangential unit, thus increasing the potential for carbon burnout problems. Also, the degree of flame interaction, based on the burner heat input relative to the vertical burner spacing, is somewhat high. All of these factors may limit the amount of combustion staging and lower the NO_x reduction performance from a retrofit OFA system.

For thermal NO_x effects, both the furnace volumetric and burner zone heat release rates (20,000 Btu/hr-ft^3 and 380,000 Btu/hr-ft^2, respectively) are high. Fuel NO_x effects are unknown due to lack of data on fuel nitrogen and O/N ratios.

Finally, the plant indicated no significant slagging problems on unit 3. It is estimated that a retrofit OFA system applied to unit 3 would have low to intermediate NO_x reduction performance of 10 to 20 percent. This estimate is based on balancing the low slagging tendency of the coal with the somewhat restricted space above the top burners for the OFA retrofit.

8.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700^{o}F for coal-fired systems typically restrict the SCR system location to between the economizer and air heater at the tail end of the unit or before the chimneys. The tail end system requires a flue gas reheat system before the reactor.

For units 1-3, it was assumed the tail-end SCR system would be used to minimize unit down time. Boiler 1-3 flue gases would be diverted after passing through the ESPs to the reheater and through the catalyst. Hot flue gas from the reactor would be cooled before returning to the chimney. The catalytic reactors would be located behind each unit near each chimney.

Table 8-14 summarized the SCR retrofit difficulty and scope adjustment for boiler units 1-3. The retrofit factor includes access and congestion and underground obstruction considerations. The area behind units 1-2 is moderately congested, and moderate to high difficult factors were assigned. However, the area beside unit 3 is not congested and a low difficulty factor assigned.

8.4.3 Summary of NO_x Control Costs

Table 8-15 and figure 8-11 present the annual cost of NO_x controls. LNB on unit 1 assumes a 50 percent NO_x reduction, while OFA on units 2 and 3 assumes 25 and 20 percent NO_x reduction, respectively. SCR on units 1-3 assumes an 80 percent NO_x reduction. LNB and OFA retrofits would result in a plant level NO_x reduction of 3,500 tons per year. The cost effectiveness of LNC ranges from \$103 to \$456 per ton of NO_x removed. Application of SCR would reduce NO_x emissions by 9,400 tons per year if 80 percent reduction can be achieved; the cost per ton of NO_x removed ranges from \$5,704 to \$6,548 per ton of NO_x removed.

TABLE 8-14. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR BROWN PLANT (August 1987 Dollars)

Item	Boiler 1	Boiler 2	Boiler 3
Site access and congestion for SCR reactor	High	Medium	Low
SCOPE ADDER PARAMETERS			
Building demolition (1,000$)	0	0	0
Ductwork demolition (1,000$)	50	50	77
New duct length (feet)	340	180	350
New duct costs (1,000$)	1,685	1,157	3,919
New heat exchanger (1,000$)	1,864	2,434	4,301
Total scope adder costs (1,000$)	3,599	3,641	8,297
Retrofit factor for SCR	1.52	1.34	1.16
General facilities (percent)	17	13	13

TABLE 8-15. NO_X CONTROLS COSTS FOR BROWN PLANT (August 1987 Dollars)

NO_x Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X Reduced (tons/yr)
Low NO_x Burner	1	50	21.6	456	1.0	1,000
Overfire Air	2	25	4.0	183	0.1	700
	3	20	2.3	103	0.1	1,800
Selective Catalytic Reduction	1	80	232.1	6,548	22.8	1,500
	2	80	170.8	5,846	14.6	2,200
	3	80	127.8	5,704	14.2	5,700

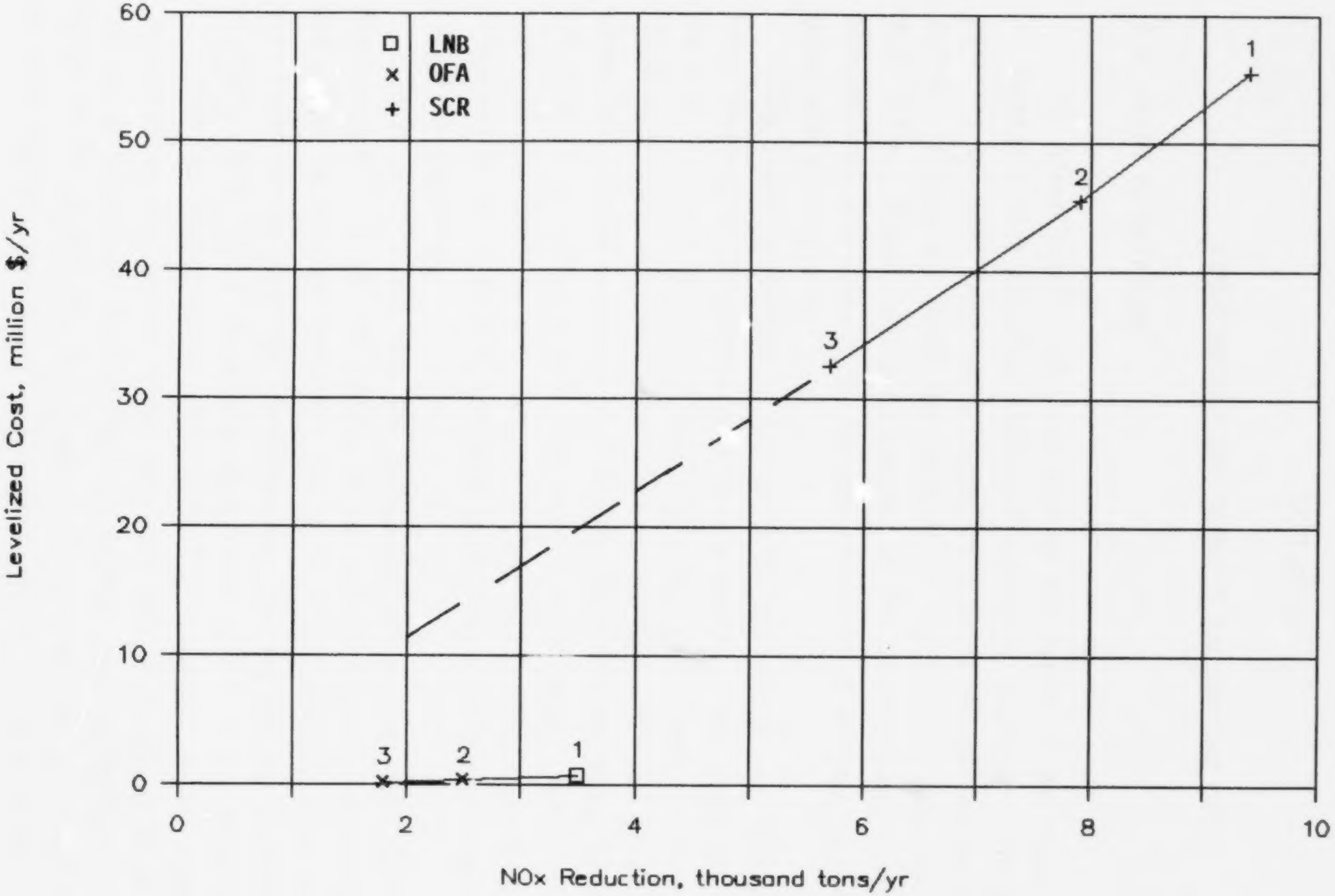

Figure 8-11. Brown Plant NO_x controls cost versus NO_x reduction.

SECTION 9

ELMER SMITH PLANT RETROFIT FACTORS AND COSTS

9.1 PLANT DESCRIPTION

The Elmer Smith Plant, operated by the Owensboro Municipal Utilities, is located within the city limits of Owensboro, Kentucky. The plant contains two coal-fired boilers and has a total net generating capacity of 416 MW. Figure 9-1 shows the location of the boilers, powerhouse, and other facilities. Approximately 60 percent of the plant's power output goes into the Kentucky utilities grid, and the remaining 40 percent is used by the Owensboro municipality.

The plant is bounded to the north by the Ohio River, to the east by heavy commercial industries, and to the west by light commercial structures and a U. S. Coast Guard Station. The plant site proper is bounded to the south by Highway 60. The total site is approximately 165 acres, of which approximately 150 acres are in the main block located north of Highway 60. The site is served by a spur from the L & N Railroad. Two large open areas surround the plant to the east and to the west. All future expansions were projected to be located in the east open area, but no plans currently exist for plant additions.

Table 9-1 presents the key design and operational data for the plant. Unit 1, a 151 MW cyclone boiler manufactured by Babcock and Wilcox, was placed in service in 1964. Unit 2 is a 265 MW pulverized, dry-bottom, coal-fired boiler built by Combustion Engineering and was placed in service in 1974. Unit 1 is a swing load unit while unit 2 is the base load unit.

From the storage pile, coal is sent by conveyors to the bunker house located above the turbine room. The coal pile is designed for a 90-day coal storage at 60 percent load. The live storage area is located about 50 feet southeast of the crusher house and contains a two-day supply at base load. The dead storage area makes up the remainder of the pile except for a small

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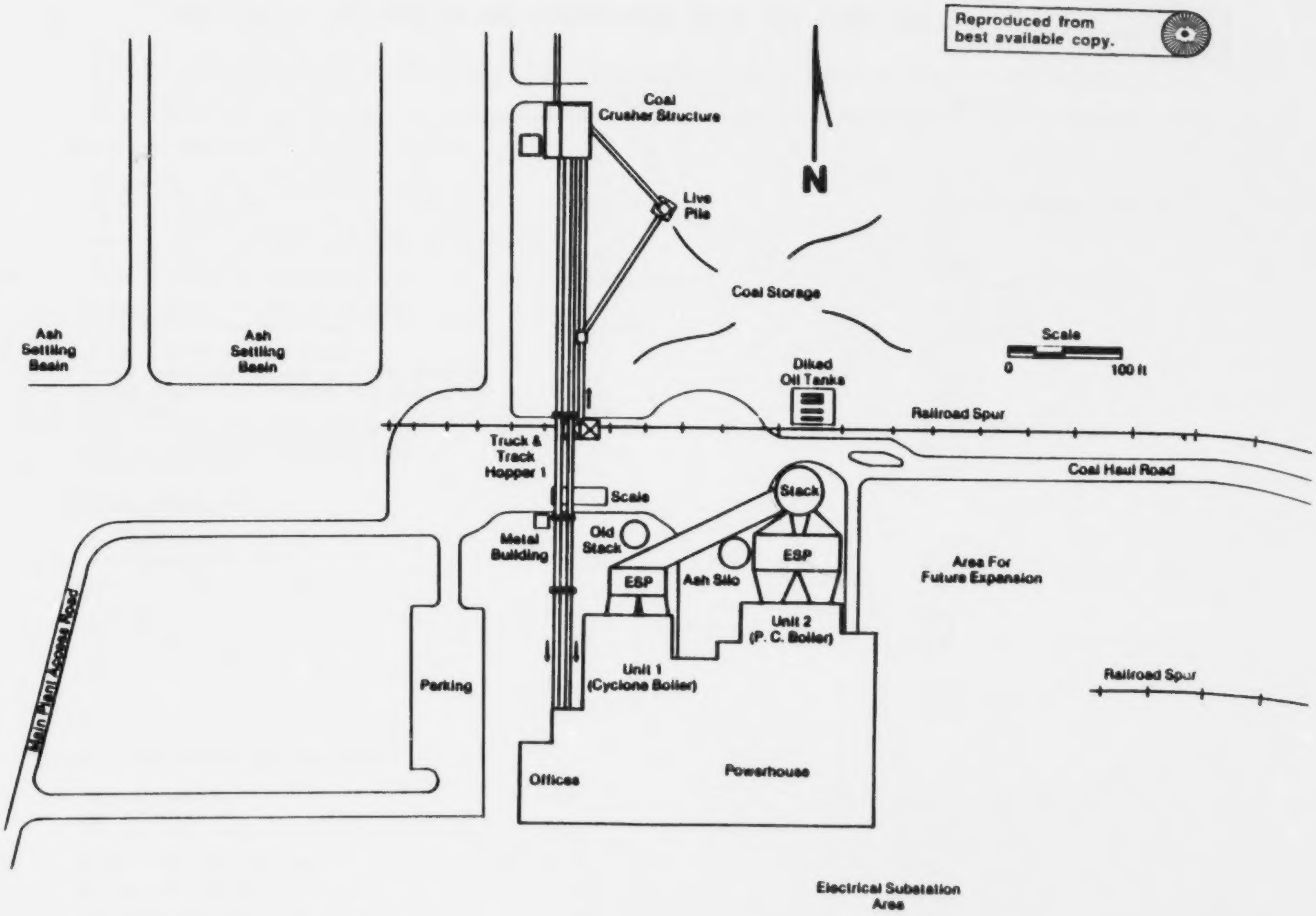

Figure 9-1. Elmer Smith plant plot plan.

TABLE 9-1. KEY DESIGN AND OPERATIONAL DATA FOR ELMER SMITH PLANT

Item	Boiler 1	Boiler 2
BOILER AND STACK DATA		
Net generating capacity (MW)	151	265
Boiler manufacturer	Babcock & Wilcox	Combustion Engineering
Installation Date	1964	1974
Capacity factor (10 year projected)	30	50
Heat rate (Btu/kW-hr)	10,500	10.050
Boiler type/firing type/bottom type	Cyclone/wall/wet	P.C./tangential/dry
Boiler dimensions, (ft, D x W x H[a])	12 x 24 x	45 x 35 x 78
Burner type/number of burners (# EL x #/EL)	Cyclone/2x	Tangential/4x4
Burner spacing (vert x horiz, ft)	--[b]	4x--[b]
Burner zone heat release rate (Btu/hr-ft^2)	--[b]	401,000
Design Oxygen Level (percent O_2)/excess air	3.5/16	3.5/20
Draft type	Forced	Forced
Flue gas flow rate (1000 acfm @ °F)	460 @ 300°F	1015 @ 320°F
Stack size (height x diameter, feet)	650 x 18	650 x 18
Stack liner type	Steel	Steel
FUEL AND SORBENT DATA		
Coal quality[c]		
Heat content (Btu/lb)	10,673	10,673
Volatile matter (percent)	--[b]	--[b]
Ash (percent)	11.5	11.5
Moisture (percent)	11.5	11.5
Sulfur (percent)	2.9	2.9
Coal delivery methods		
Current	Truck	Truck
Design	Truck/rail	Truck/rail
Likely method for sorbent delivery		
PARTICULATE CONTROL EQUIPMENT DATA		
Type of control	ESP	ESP
Installation date		
ESP specific collection area (ft^2/10^3 acfm)	154	225
Total plate area (10^3 ft^2)	89.3	157
Emission standards (lb/10^6 Btu)	0.28	0.21
ESP outlet emissions (lb/10^6 Btu)[d]	0.093	0.164
Design coal sulfur (percent)	2.7	2.7
Gas conditioning	None	None
Tested efficiency/design efficiency	--[b]/97.0	--[b]/98.0

(Continued)

TABLE 9-1. (CONTINUED)

Item	Boiler 1	Boiler 2
NITROGEN OXIDE CONTROL EQUIPMENT DATA		
NO_x control equipment	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA		
SO_2 control equipment	None	None
SOLID WASTE DISPOSAL DATA		
Ash transport system type		
Boiler bottom ash	Wet sluice	Wet sluice
Fly ash	Wet sluice	Wet or dry
Ash disposal method	Pond/truck-off	Sell (fly ash) or pond/truck-off
Existing pond capacity		
Estimated distance to off-site waste disposal	On-site	On-site

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

amount of low sulfur coal stored on the eastern edge of the pile. Low-sulfur coal blending occasionally is done at the plant. Currently the plant has a three year "time and quantity" contract with a local coal supplier. The 2.9 percent sulfur coal is delivered to the plant by truck (rail delivery facilities also are available).

Particulate emissions from both boilers are controlled with electrostatic precipitators (ESPs). The unit 1 ESP has a specific collection area (SCA) of 154 $ft^2/10^3$ acfm and was designed for a coal sulfur content of 2.7 percent. Emission tests indicate unit 1 ESP emits 0.093 $lb/10^6$ Btu at full load, well below the current emission standard of 0.28 $lb/10^6$ Btu. Unit 2 ESP has an SCA of 225 $ft^2/10^3$ acfm, and was designed for a coal sulfur content of 2.7 percent. Emission tests on unit 2 ESP have shown it emits 0.164 $lb/10^6$ Btu at full load, also below the current standard of 0.21 $lb/10^6$ Btu.

Ash from the unit 1 ESP, boiler, and economizer is sluiced to ash settling ponds at the northwest corner of the plant. These ponds are periodically dredged, and the solid waste is trucked off for off-site disposal. Unit 2 boiler and economizer ash is also sluiced, but ESP ash from unit 2 is handled dry and is sent to an ash storage silo adjacent to the unit 2 ESP. The unit 2 fly ash can also be sluiced to the settling ponds if the ash silo is full. Ash from this silo is sold to a local concrete plant. Water overflow from the ash settling pond system is discharged into the Ohio River at a pH of between 6 and 9.

9.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercialized SO_2 control technologies evaluated for the Elmer Smith Plant include lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching, and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates developed.

9.2.1 Lime/Limestone and Lime Spray Drying Flue Gas Desulfurization

9.2.1.1 Control Cases Evaluated--

Table 9-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. A low capital cost L/LS FGD case was evaluated for each boiler. For this case, a combined system for both boilers was not evaluated because flue gas duct run distances and access/congestion to tie boiler 1 to boiler 2 would negate any cost savings due to economies-of-scale.

For LSD-FGD systems, two options were evaluated, one where the existing ESPs are used to collect the fly ash and spray dried solids, and one where a new baghouse is installed. IAPCS estimates that the unit 1 ESP would require a significant increase in SCA. As a result, LSD FGD with ESP reuse was not considered for unit 1. For this unit, LSD FGD with a new baghouse was evaluated and the SO_2 removal efficiencies was estimated to be 86 percent. For unit 2, LSD FGD with ESP reuse and new baghouse were both evaluated because the ESP is only marginally large enough for reuse. Due to the higher SO_2 removal that occurs in a baghouse versus an ESP, the SO_2 removal efficiencies of 81 and 66 percent were estimates, respectively.

9.2.1.2 Layout of Equipment and Design Basis--

An important consideration in the development of retrofit factors and costs is the placement of the major components of the SO_2 control system at the site. Site specific access/congestion and other factors can impact retrofit cost. For each SO_2 control case considered, a simplified plant drawing or conceptual design is prepared which illustrates the placement of the key components of each SO_2 control system and which is used in the development of retrofit difficulty and other retrofit cost considerations. Absorbers, spray dryers, ductwork, baghouses, clarifiers/vacuum filters, sorbent preparation, sorbent receiving, and storage, and FGD waste storage systems are shown on each drawing. Also, each drawing was reviewed for accuracy and completeness by plant personnel at the Elmer Smith Plant.

TABLE 9-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR ELMER SMITH PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt %)	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	2.7	8,900
Boiler 2	90	2.7	26,000
LSD FGD (reuse ESP)			
Boiler 2	66	2.7	19,100
LSD FGD (new baghouse)			
Boiler 1	86	2.7	8,600
Boiler 2	81	2.7	23,300
LOW COST CONTROLS			
L/LS FGD			
Boiler 1	90	2.7	8,900
Boiler 2	90	2.7	26,000

The size of a specific control system component, such as absorbers, is key in deciding where to place those components at the site. The equipment sizes were developed based on EPRI guidelines and on actual retrofit FGD system designs.

Several key factors were considered in developing the control system designs illustrated in figures 9-2 through 9-4. All of these considerations were best satisfied by placing the majority of the control equipment in open areas to the west of unit 1 and the east of unit 2. These open areas allowed somewhat conventional system layouts to be developed for most of the LSD FGD and L/LS FGD cases evaluated.

9.2.1.3 Scope Adjustments--

In order to retrofit control systems at Elmer Smith, some existing equipment must be modified and costs not included in the IAPCS cost models must be added to account for this equipment. These are referred to as scope adjustments or cost adders and are summarized in table 9-3 for all FGD cases evaluated.

Conversations with plant personnel indicated that a portion of the existing rail lines within the plant are in need of repair. Since in the FGD system designs it is assumed that a portion of the in-plant lines are used for receiving lime and/or limestone shipments, the cost of repairing a portion of those lines was included. Costs used are based on estimates supplied by ConRail and account for replacement of ties and some rails.

The cost of converting the unit 1 ESP ash removal and conveyance system from a wet to a dry system was also included. Dry waste is necessary for L/LS FGD sludge stabilization. Conversion of the unit 2 ash system was not necessary since it can operate in either the wet or dry mode.

The costs for balanced draft controls; building, electrical, and duct demolition; and stack relining were based on EPRI guidelines cost of $40 per square feet of liner surface area. The cost to relocate the metal shed, plant roads, and parking areas was accounted for in the general facilities cost. For all cases, a 5 percent general facilities factor was used for unit 2 while factors between 5 and 10 percent were used for unit 1.

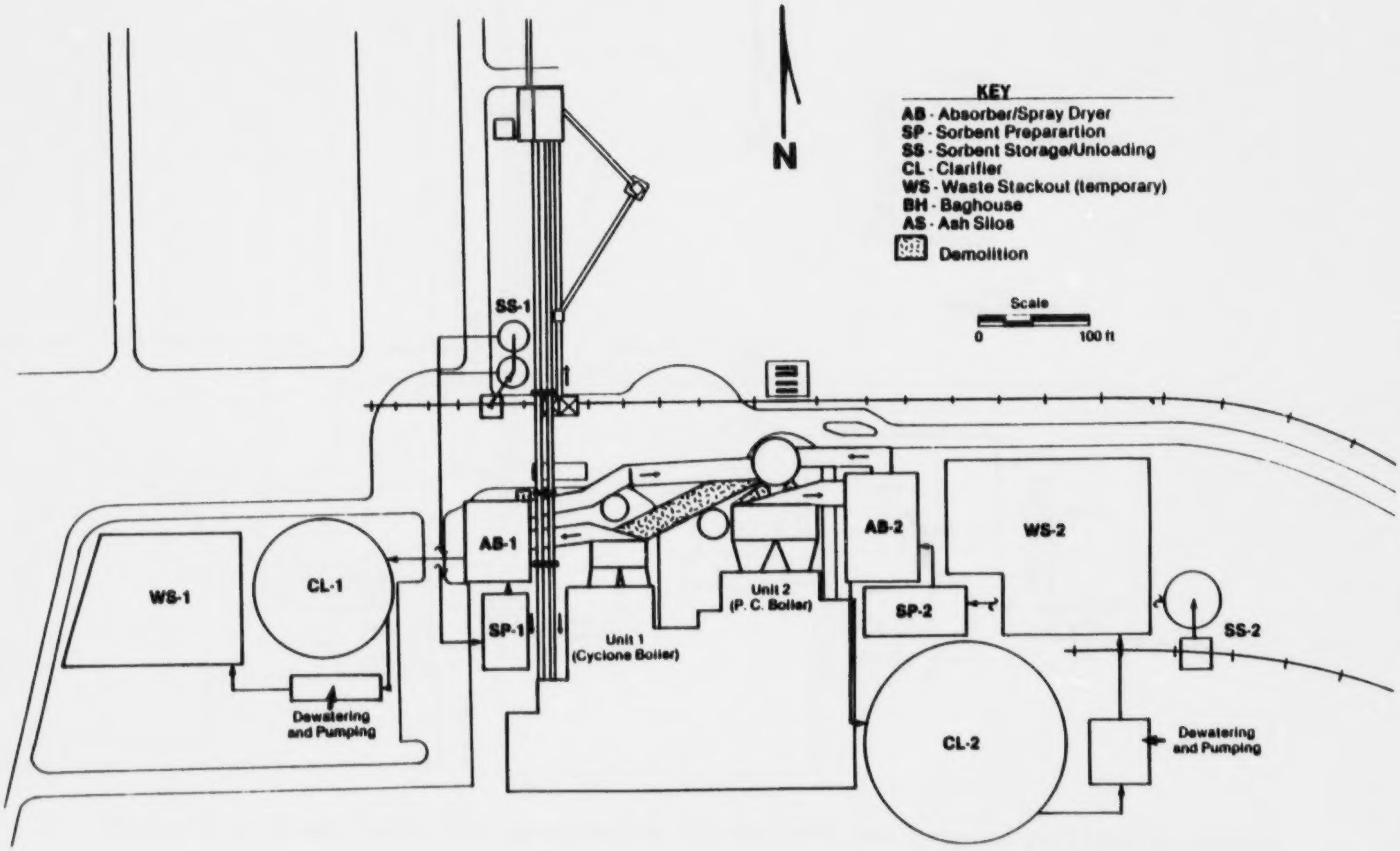

Figure 9-2. Elmer Smith lime/limestone flue gas desulfurization systems.

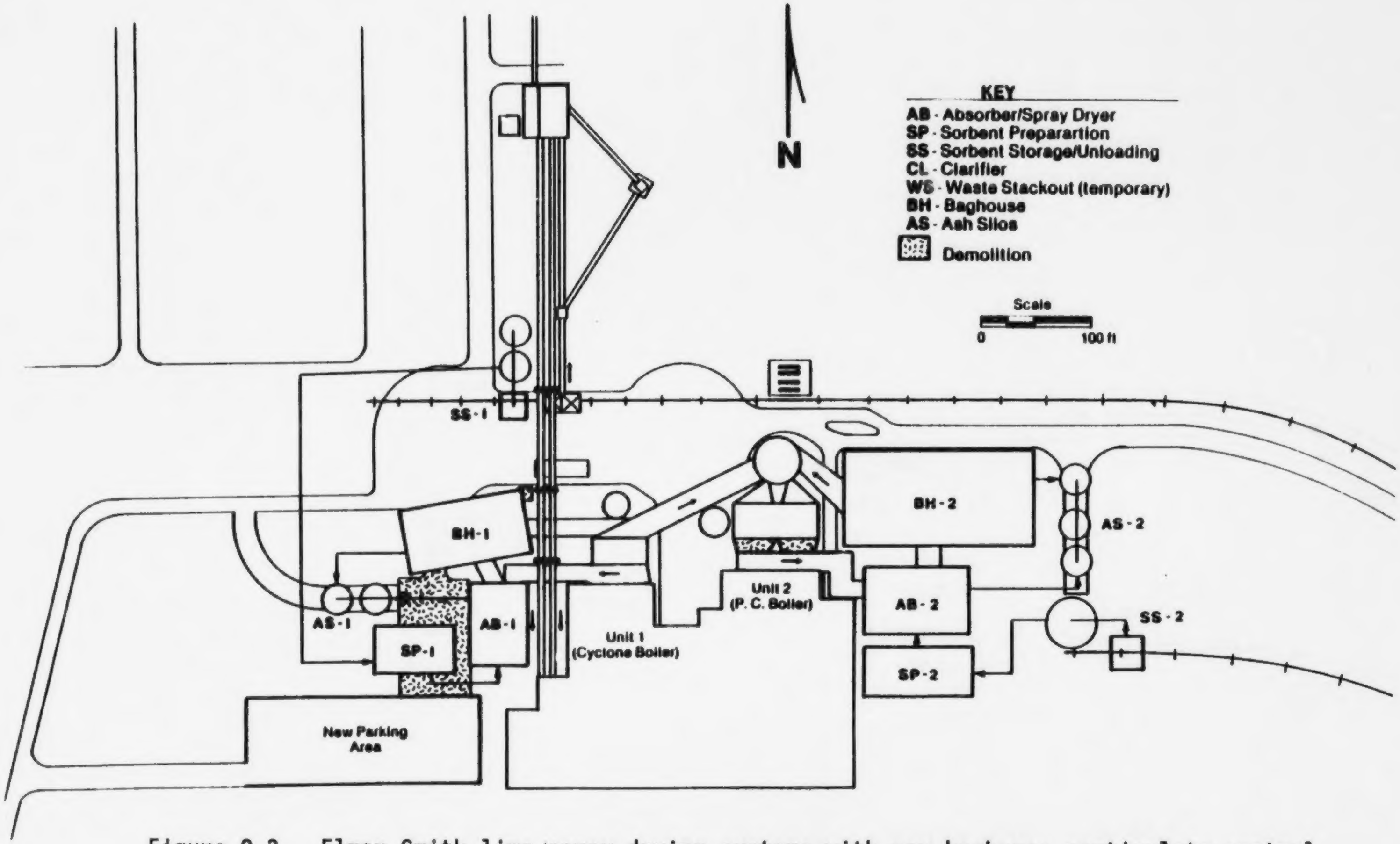

Figure 9-3. Elmer Smith lime spray drying systems with new baghouse particulate control.

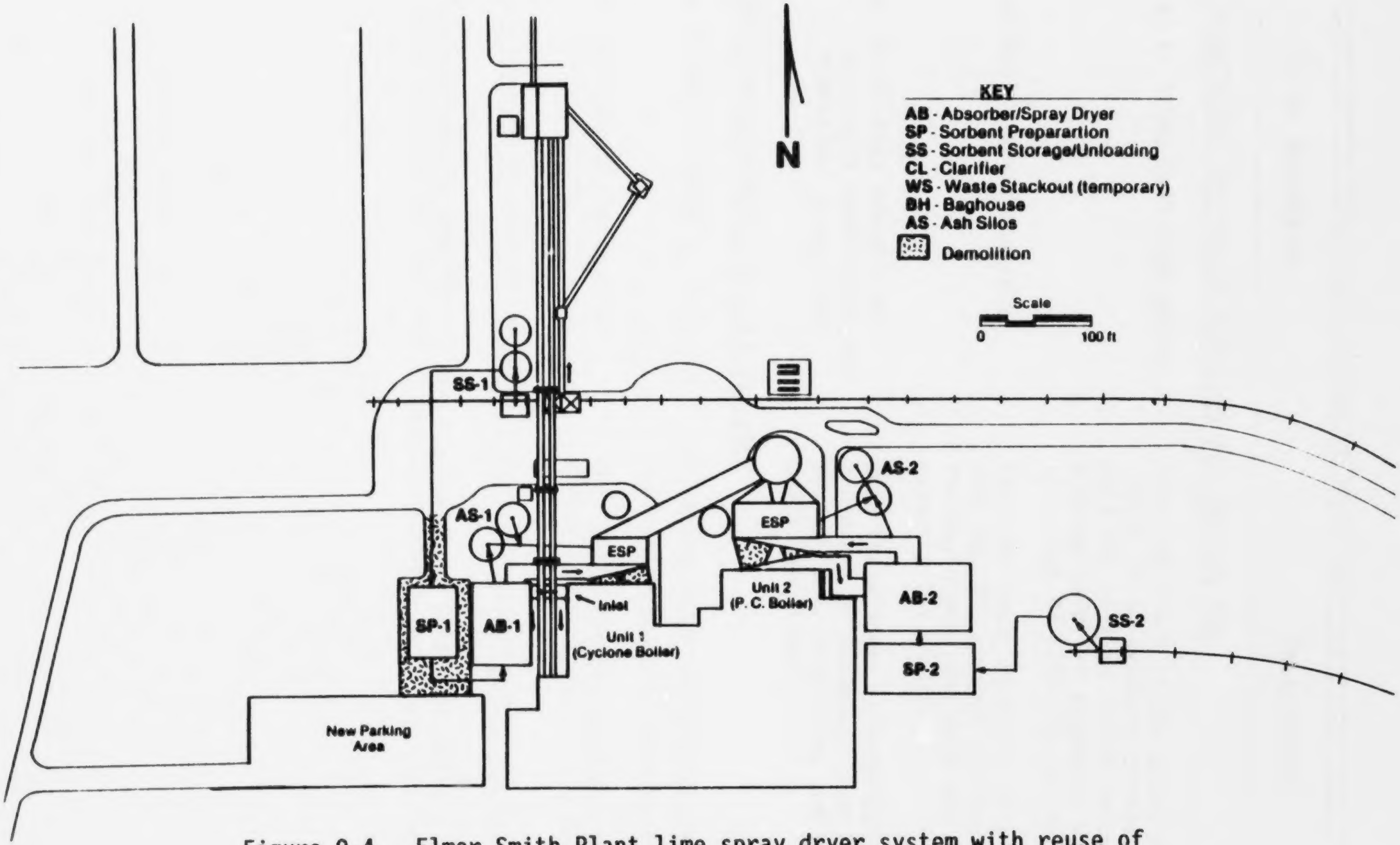

Figure 9-4. Elmer Smith Plant lime spray dryer system with reuse of existing particulate control system.

TABLE 9-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR ELMER SMITH PLANT

Scope Adjustment	Description[a]
ADJUSTMENTS APPLIED TO BOTH L/LS FGD AND LSD FGD	
• Existing rail line repair	Some old track at the plant needed repair to accommodate sorbent shipments. Half the in-plant track north of the highway used for shipments was repaired at a cost of $250,000 per mile.
• Modify draft controls	Balanced draft controls were required with new SO_2 control systems due to increased pressure drop and added fan capacity ($1.20/kW).
• Metal shed demolition, duct work demolition, and electrical demolition	When these items interfered with the placement of equipment (see figures 9-2 through 9-4) demolition and relocation costs were added.
ADJUSTMENTS APPLIED TO L/LS FGD ONLY	
• Stack relining	Existing stack relined to prevent corrosion: ($40/ft^2 base cost).
• Ash removal/conveyance modification	Unit 1 ESP system changed from wet sluice to dry handling ($9.13/kW).

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

9.2.1.4 Location and Retrofit Factors--

Tables 9-4 and 9-5 present the location and retrofit factors used for L/LS and LSD FGD. These factors are site specific constraints that account for the cost associated with the site specific difficulty of retrofitting control equipment. The aggregate location factor presented in the column titled LOCF incorporates the following factors: seismic zone factor of 3.0, since the plant is in an area where major damage could occur in the event of an earthquake; climate zone factor of 0.99, and labor productivity and materials factor of 1.06 (Kentucky).

The soil factors selected are equal to the EPRI base case since soil conditions are similar to the base case: poor bearing capacity soil with deep bedrock. Available data indicate that the soil at the Elmer Smith Plant has an average bearing capacity of 2,000 lb/ft^2.

For unit 1, several constraints are encountered which impact costs, including:

- overhead coal conveyor system and supports which limit vertical and horizontal ductwork clearances (this obstruction also accounts for the medium access/congestion assigned to the SO_2 removal and particulate collector systems),

- A significant number of underground obstructions are located just west of the coal conveyance system including ash sluice lines, circulating water lines, plant drainage systems, and fire hydrant lines. The area to the east of unit 2 has no such obstructions.

- Abandoned stack to the north of the ESP limits the duct clearance at the ESP outlet and requiring special duct designs and supports when routing ducts to the existing stack,

TABLE 9-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR ELMER SMITH PLANT

		RETROFIT FACTORS							
	All Units	Boiler #1				Boiler #2			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.06	1.13	1.15	1.00	1.30	1.00	1.15	1.00	1.15
SO_2 Removal	1.06	1.06	1.30	1.00	1.38	1.00	1.30	1.00	1.30
Flue Gas Handling	1.08	1.06	1.50	1.24	1.97	1.00	1.02	1.08	1.10
Waste Handling	1.08	1.14	1.02	1.00	1.16	1.00	1.02	1.00	1.02
General Support Equipment	1.06	1.06	1.24	1.00	1.31	1.00	1.24	1.00	1.24
SCOPE ADJUSTMENTS									
Chimney	1.07	1.00	1.06	1.00	1.06	1.00	1.06	1.00	1.06
Wet to Dry Ash System	1.00	1.00	1.30	1.00	1.30	N/A[f]	N/A	N/A	N/A
Rail Repair	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %				12.5				11.5	
General Facilities - %				5.0				5.0	

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 9-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

[f] N/A = Not applicable.

TABLE 9-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR ELMER SMITH PLANT

		RETROFIT FACTORS							
	All Units	Boiler #1				Boiler #2			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.06	1.06	1.05	1.00	1.11	1.00	1.15	1.00	1.15
SO_2 Removal	1.06	1.06	1.30	1.00	1.38	1.00	1.30	1.00	1.30
Flue Gas Handling[f]	1.07	1.06	1.50	1.13	1.80	1.00	1.02[g]	1.10	1.12
General Support Equipment	1.06	1.06	1.24	1.00	1.31	1.00	1.24	1.00	1.24
SCOPE ADJUSTMENTS									
Wet to Dry Ash System	N/A[h]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Rail Repair	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Baghouse	1.06	1.06	1.30	1.00	1.38	1.00	1.10	1.00	1.10
ESP Plate Area Addition	N/A	N/A	N/A	N/A	N/A	1.00	1.50	1.00	1.50
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			12.5					11.5	
General Facilities - %			10.0					5.0	

---

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor. See table 9-7 for distance assumptions.

[d] DISF = Distance Factor

[e] AGGF = Aggregate Factor

[f] Flue gas handling aggregate factor includes duct work tie-in costs.

[g] For the ESP reuse case a value of 1.50 was used.

[h] N/A = Not applicable.

- Generally limited space in which to make duct turns, and

- Main plant access road which ducts must be routed over.

Table 9-6 summarizes retrofit factors for the low cost L/LS FGD case. Table 9-7 presents duct tie-in distances and distances between process areas. Long tie-in ductwork distances impact retrofit costs significantly.

9.2.1.5 Overall Retrofit Factors and Costs--

Table 9-8 presents the overall retrofit factors and costs for all FGD cases. The range of costs shown for L/LS FGD reflect the different process options evaluated: conventional and adipic acid enhanced limestone FGD and conventional and MgO enhanced lime FGD. The LSD FGD costs include 1) upgrading the ESPs and ash handling system for unit 2, and 2) installing new baghouses to handle the additional particulate loading for units 1 and 2.

Figures 9-5 and 9-6 summarize the plant level costs of installing L/LS and LSD FGD. Control systems were applied sequentially to each boiler, beginning with the lowest unit cost per ton of SO_2 removed. The data point labeled low cost shows the impact of scrubber module optimization. As Table 9-8 shows and as the figures imply, unit 2 has the lowest cost per ton for both L/LS and LSD FGD technologies. Unit 2 is larger and has lower retrofit factors compared to unit 1.

The addition of L/LS FGD is estimated to reduce plant-wide SO_2 emissions by 34,900 tons per year assuming 90 percent emission reduction. For application of LSD-FGD, the estimated emission reduction is 27,700, tons per year with ESP upgrade at Unit 2 and a new fabric filter at Unit 1 and 31,900 tons per year if replacement fabric filters are installed at both units. The low capital cost case reduces annual operating costs by 45 percent versus the conventional L/LS FGD cases.

TABLE 9-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES FOR ELMER SMITH PLANT

Item	All Units LOCF[a]	RETROFIT FACTORS							
		Boiler #1				Boiler #2			
		UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.06	1.13	1.15	1.00	1.30	1.00	1.15	1.00	1.15
SO_2 Removal	1.06	1.06	1.30	1.00	1.38	1.00	1.30	1.00	1.30
Flue Gas Handling	1.08	1.06	1.50	1.24	1.97	1.00	1.02	1.08	1.10
Waste Handling	1.08	1.14	1.02	1.00	1.16	1.00	1.02	1.00	1.02
General Support Equipment	1.06	1.06	1.24	1.00	1.31	1.00	1.24	1.00	1.24

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 9-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 9-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR ELMER SMITH PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
INDIVIDUAL CONTROLS				
L/LS FGD				
Boiler 1	125	265	50	100
Boiler 2	105	125	50	100
LSD FGD (new baghouse)				
Boiler 1	145	140	50	N/A[c]
Boiler 2	145	100	50	N/A
LSD FGD (reuse ESP)				
Boiler 2	95	130	50	N/A
LOW COST CONTROLS				
L/LS FGD				
Boiler 1	125	265	50	100
Boiler 2	105	125	50	100

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

TABLE 9-8. L/LS AND LSD FGD COSTS FOR ELMER SMITH PLANT
(August 1987 Dollars)

		IAPCS Retrofit Costs[a]		
Case Description	Overall Retrofit Factor	Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.66	335.1-388.5	1,906-2,124	42.5-47.6
Boiler 2	1.26	212.3-245.4	867-980	19.4-22.0
LSD FGD (reuse ESP)				
Boiler 2	1.38	177.8	846	13.9
LSD FGD (new baghouse)[b]				
Boiler 1	1.88	380.4	1,923	41.4
Boiler 2	1.64	241.4	881	17.7
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.66	226.5	1,305	29.3
Boiler 2	1.26	138.4	589	13.2

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] Includes impact of new baghouse.

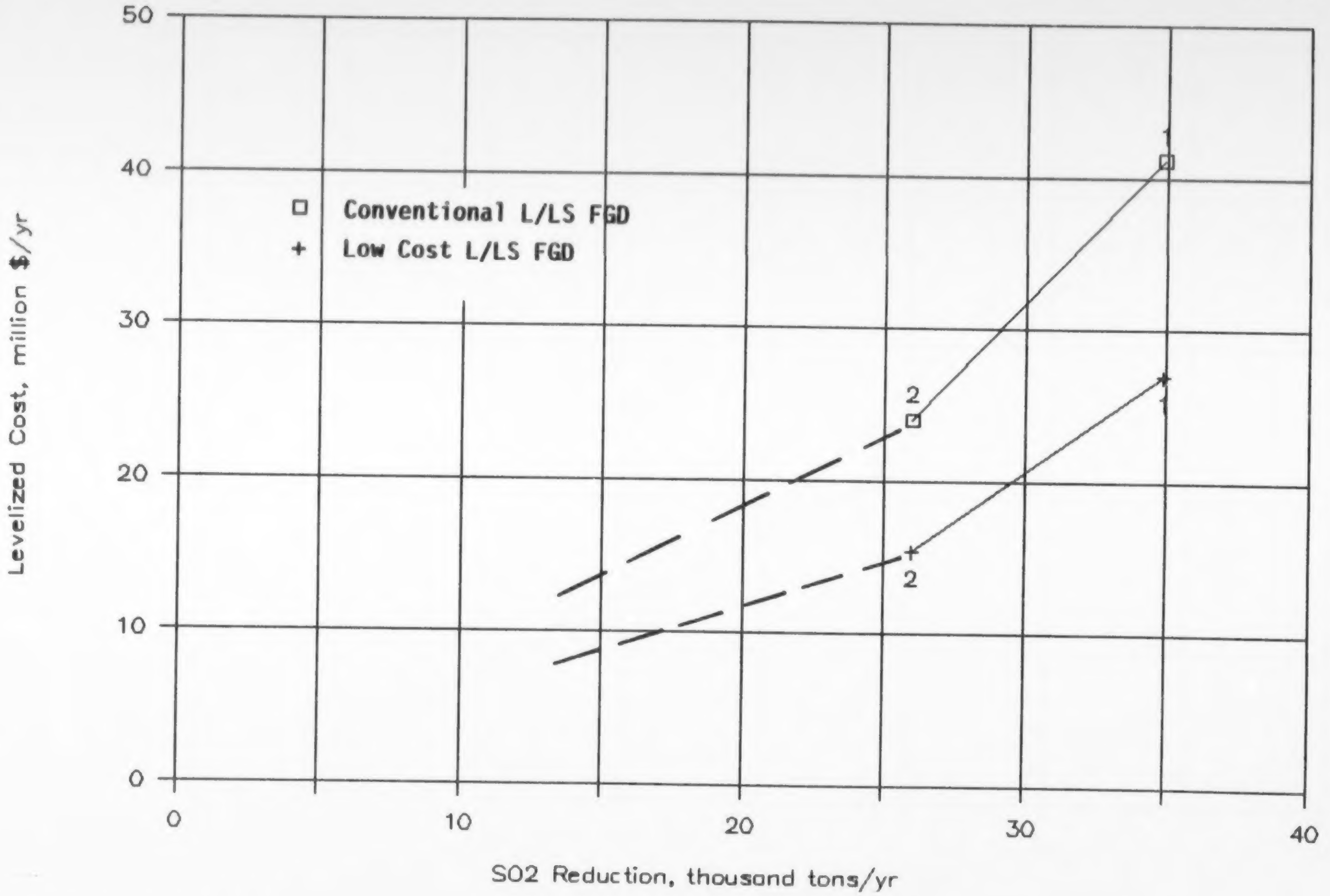

Figure 9-5. Elmer Smith L/LS cost versus SO_2 reduction.

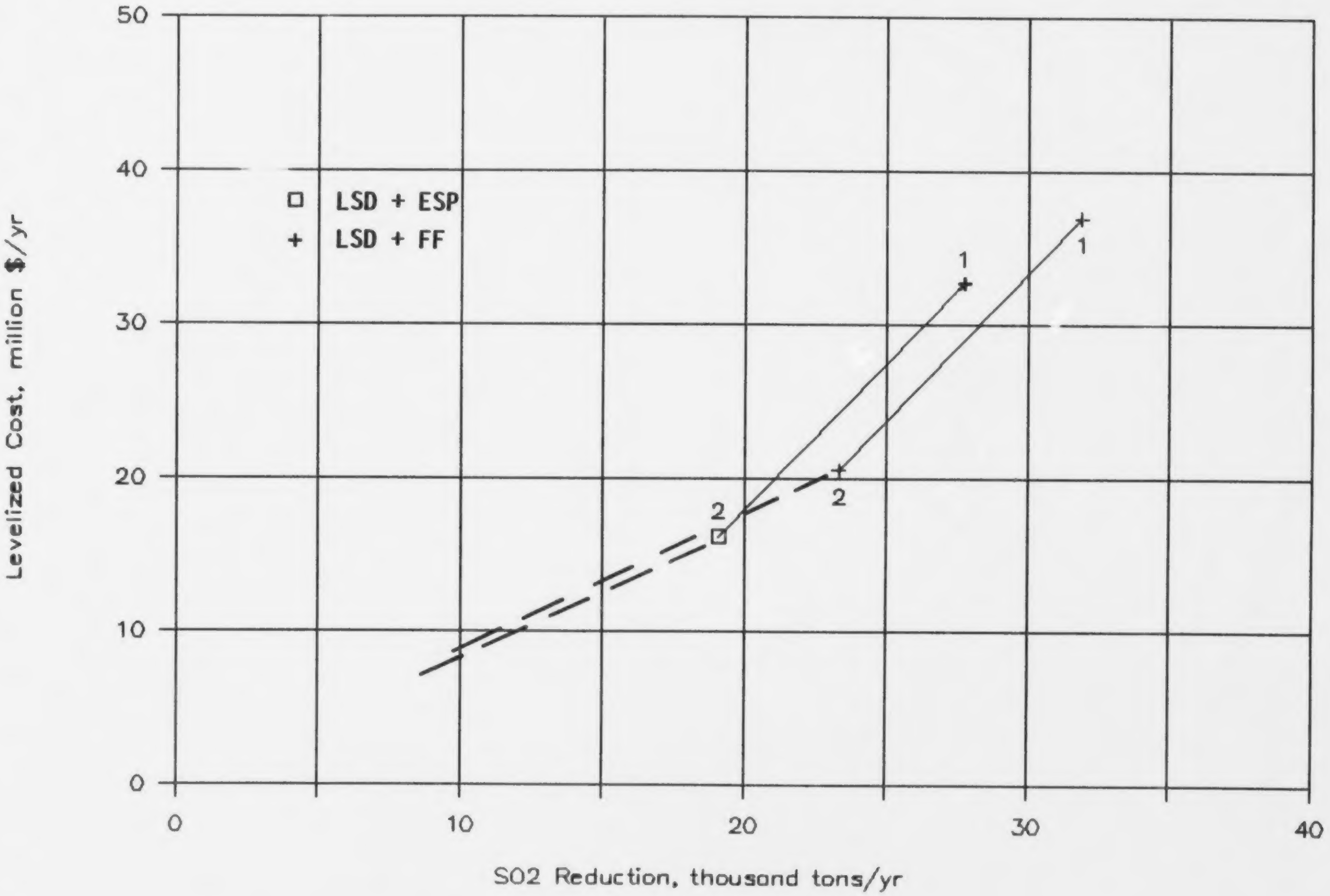

Figure 9-6. Elmer Smith Plant lime spray dryer FGD cost versus SO_2 reduction.

9.2.2 Coal Switching/Blending

Table 9-9 presents the coal analyses for coal used in 1985 and the alternative coal used to evaluate coal switching. The switch coal is low-sulfur Kentucky coal having a sulfur content of 1 percent.

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

ESP performance impacts were evaluated using the IAPCS model to setiamte the needed plate area. This plate area was compared to the existing are to determine whether SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. For boilers 1 with SO_3 conditioning, a 38 percent increase in the existing ESPs would be needed for low-sulfur coal service. However, because the benefits of SO_3 conditioning are highly variable, the predicted ESP plate area increase should be viewed as a minimum estimate. For boiler 2, no plate area addition would be required. Table 9-9 also presents the ESP parameter requirements for switching.

Figure 9-7 presents the plant level cost and emission reduction for switching to a low sulfur coal. Curves were generated to show the impact of different coal fuel price differentials. The lower curve represents a 1985 levelized fuel price differential of $4.84 per ton between the existing coal and an eastern Kentucky low sulfur coal. The upper curve shows the impact of additional fuel price differentials of $15 per ton over the 1985 fuel price.

Approximately 26,300 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.6 pound per million Btu SO_2 emission rate. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 9-10. For unit 1 and 2, the plant may decide to replace the existing ESPs with new particulate controls because of their small SCAs. If this were the case, new particulate control capital investment of 8.9 and 14.0 million dollars would be required for units 1 and 2, respectively.

TABLE 9-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR ELMER SMITH PLANT

	Existing Coal		Switch Coal		Cleaned Coal	
	Boiler		Boiler		Boiler	
Item	1	2	1	2	1	2
COAL PARAMETERS						
Percent Sulfur	2.7	2.7	1.0	1.0	2.2	2.2
Percent Ash	11.5	11.5	10.5	10.5	6.0	6.0
Btu Per Pound	10673	10673	12100	12100	11900	11900
ESP PARAMETERS						
Existing/ Needed SCA[a]	154	225	163	163	163	163

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

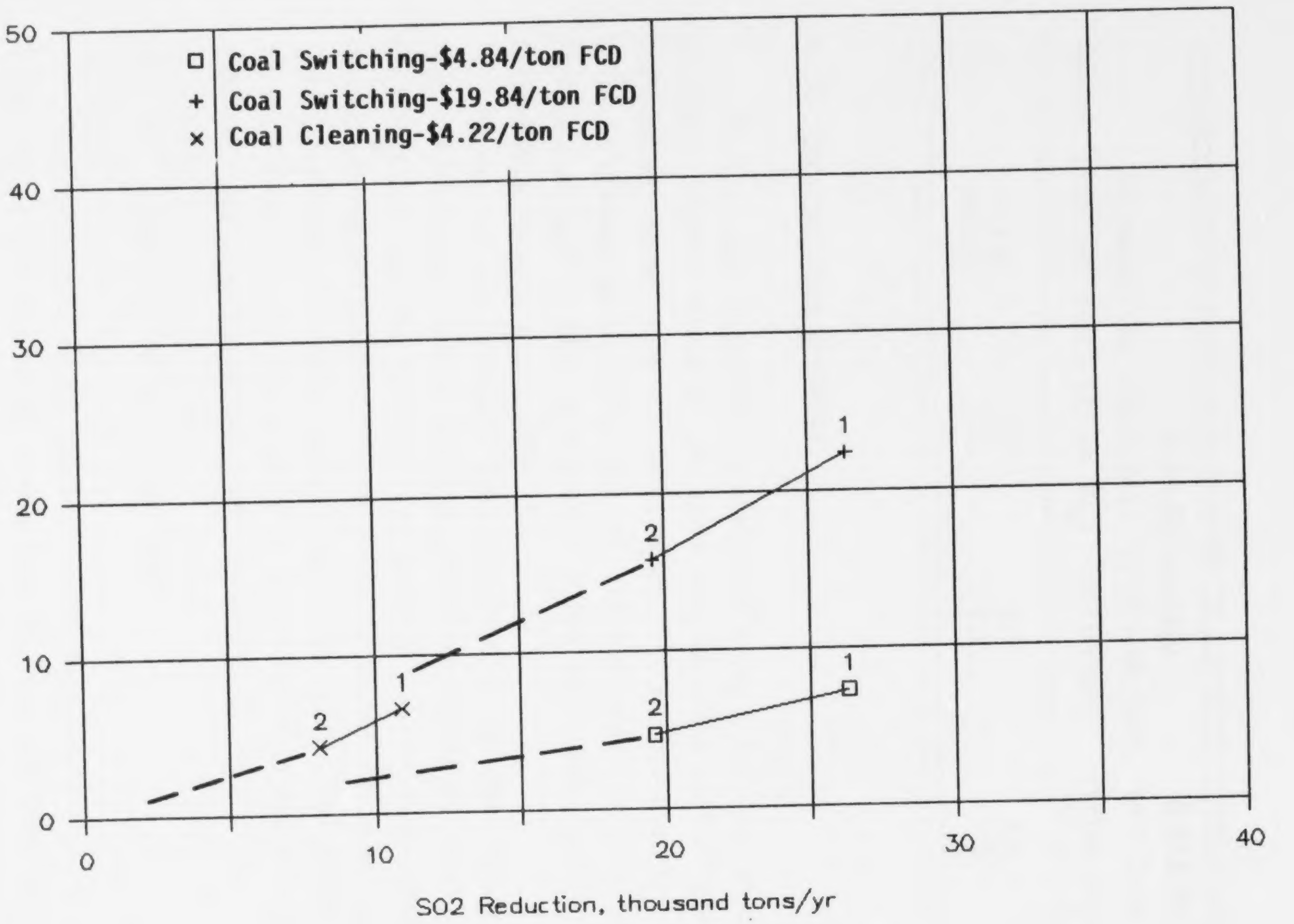

Figure 9-7. Elmer Smith Plant coal switching/cleaning costs versus SO_2 reduction.

TABLE 9-10. COAL SWITCHING COSTS FOR ELMER SMITH PLANT
(August 1987 Dollars)

		@ $4.84/ton FCD		@ $19.84/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1	6,700	395	6.7	981	16.6
2	19,600	238	4.0	802	13.6

9.2.3 Physical Coal Cleaning

Physical coal cleaning was evaluated using a high sulfur coal similar to that currently burned at the Smith station. The cost of cleaning this coal was estimated using the IAPCS model. It was assumed that the coal would be cleaned at the mine with no refuse disposal required at the plant. The cleaned coal parameters are used in the IAPCS model to estimate performance impacts on the ESPs.

Figure 9-7 also presents the IAPCS results for physical coal cleaning. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal. The costs do include the estimated increase in coal cost for the cleaning operation ($4.22 per ton). Cleaning the coal at Smith reduces the plant SO_2 emissions by 10,900 tons/yr at an average unit cost of $527 to $43 per ton of SO_2 removed. Cost estimates are shown in table 9-11.

9.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates

TABLE 9-11. PHYSICAL COAL CLEANING COSTS FOR ELMER SMITH PLANT
(August 1987 Dollars)

Boiler	SO_2 Reductions (tons per year)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
1	2,800	843	5.9
2	8,100	527	3.7

have a high degree of uncertainty due to the lack of commercial data. The following control technologies were considered: furnace sorbent injection (FSI), duct spray drying (DSD) and retrofit of fluidized bed combustion or coal gasification, for life extension and emission reduction. The following discussion presents the retrofit issues and cost/performance estimates developed.

9.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. As such, many costs for retrofit are built into the base case design and costs. The retrofit costs developed for these technologies focus on scope adders not included in developers' assumptions, including demolition/relocation of existing equipment and buildings, additional duct work, and particulate control equipment upgrading. These adder costs are adjusted to reflect the site specific access/congestion and underground obstruction costs using EPRI methodology and factors. Basic assumptions and cost adjustments made for FSI and DSD are presented in table 9-12.

9.3.1.1 Furnace Sorbent Injection--

FSI retrofit factors were developed for boiler 2 only because the ESP for unit 1 ls too small to be considered. The FSI system includes sorbent receiving/storage, sorbent transport lines and day bins, and additional ash

TABLE 9-12. SCOPE ADJUSTMENTS FOR FSI AND DSD AT ELMER SMITH PLANT

Item	Boiler 1	Boiler 2
BASIC ASSUMPTIONS		
Approximate access/congestion rank	Low	Low
Can the existing ESP be upgraded?	No	Yes
Was a new baghouse evaluated for DSD?	Yes	Yes
Distance to final waste disposal (miles)	5	5
SCOPE ADDERS		
Install dry ash handling system for ESP reuse	N/A[a]	No
New Stack	No	No
Additional duct work for new baghouse (ft)	283	245
Duct demolition length (ft)	40	47
In-plant railroad spur repair (miles)	0.2	0.2
ADDER COSTS AND RETROFIT FACTOR SUMMARY		
Scope adder costs for new baghouse (10^3 $)[b]	1,707	2,451
Scope adder costs for ESP reuse (10^3 $)[b]	N/A	410
Baghouse retrofit difficulty factor	1.38	1.10
ESP upgrade retrofit difficulty factor (for plate area addition)	N/A	1.50

[a] N/A = Not applicable.

[b] June 1985 dollars.

storage silo capacity. The FSI sorbent storage and handling equipment would be located in the open area east of unit 2 with day bins located in the area between the ESPs of unit 1 and 2.

9.3.1.2 Duct Spray Drying--

For the duct spray drying process, it was assumed the reuse of the existing ESPs at both boilers was impractical. For boiler 1 the existing ESPs will not be able to handle the increased loading due to sorbent injection. For boiler 2 the residence time in the ductwork prior to the ESP and within the ESP would not be sufficient to completely dry the injected sorbent when trying to achieve the desired SO_2 removal. Therefore, DSD with a new fabric filter was the only case considered for both units. The sorbent storage and preparation equipment would be located as for LSD FGD.

9.3.1.3 Overall Retrofit Factors and Costs--

Table 9-13 summarizes the overall retrofit factors and costs for the sorbent injection technologies. Figure 9-8 presents the cost of retrofitting FSI and DSD on boilers 1-2. For duct spray drying with a fabric filter, plant-wide SO_2 emissions are reduced by 25,300 tons per year. For the FSI technology, SO_2 emissions for Unit 2 are reduced by 14,500 tons per year under the 50 percent SO_2 case and by 20,200 tons per year under the 70 percent SO_2 removal.

9.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

Both boilers at the Smith Station were evaluated for retrofit of FBC and CG. Unit 1 is a small boiler (151 MW), has a low capacity factor (30 percent), has been in service 23 years, and has a moderate heat rate (10,500 Btu/kWh). As such, unit 1 is a likely candidate for FBC/CG life extension if significant SO_2/NO_x reduction were required. Unit 2 is a larger unit (265 MW), was started up in the mid-1970's has a moderate capacity factor

TABLE 9-13. RETROFIT COSTS FOR FSI AND DSD FOR ELMER SMITH PLANT (August 1987 Dollars)

Case Description	IAPCS Capital Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50% removal)[a]				
Boiler 2	76.2	10.2	817	14,500
Furnace Injection (70% removal)[b]				
Boiler 2	76.4	10.2	588	20,200
Duct Spray Drying (new baghouse)				
Boiler 1	215.2	26.6	1,583	6,700
Boiler 2	143.0	12.3	766	18,600

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

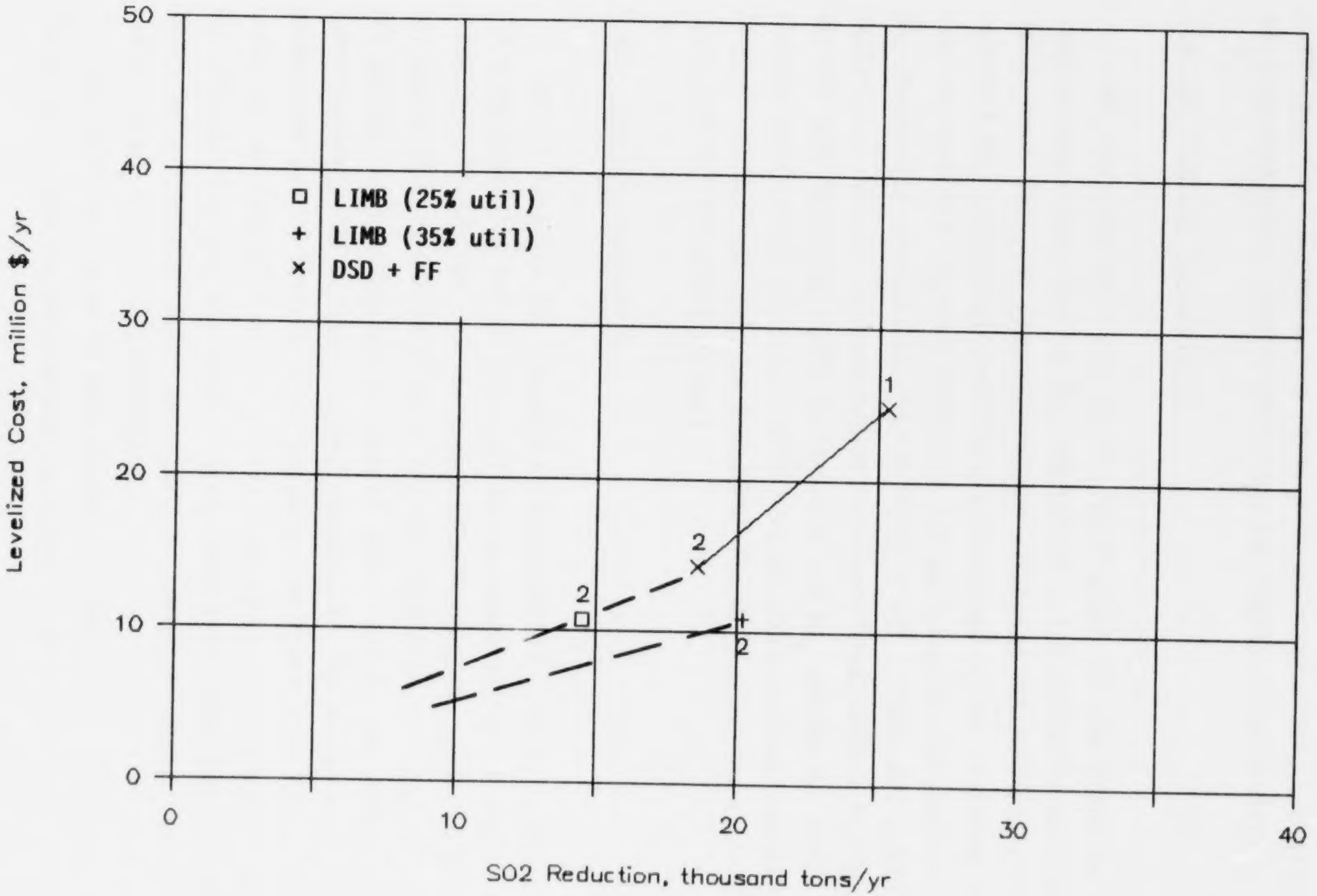

Figure 9-8. Elmer Smith Plant FSI/DSD cost versus SO_2 reduction.

(50 percent) and a heat rate of 10,500 Btu/kWh. As such, it is not a likely candidate for FBC repowering because it is a relatively new unit that should provide consistent service well into the twenty-first century.

9.4 NO_x CONTROL TECHNOLOGIES

NO_x controls evaluated at the Smith plant include overfire air and natural gas reburn for low NO_x combustion , and selective catalytic reduction. The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls are discussed in the following sections. The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls at the two Smith plant boilers are summarized in Table 9-1. Unit 1 is a wet bottom, cyclone-fired furnace design; therefore, natural gas reburning (NGR) is the only low NO_x combustion (LNC) control considered in this analysis. Unit 2 is of a dry bottom, tangential-fired furnace design, and overfire air (OFA) low NO_x combustion control has been evaluated for this type of unit.

9.4.1 Low NO_x Combustion

Unit 2 is a 265 MW, tangential-fired boiler. It is relatively small for a tangential-fired utility boiler, as compared, for example, to Brown Plant unit 3 (410 MW) and the Conesville Plant units (375-720 MW). The influence of this unit's size on the NO_x reduction performance of a retrofit OFA system can be examined in several ways. First, the burner heat input (approximately 165 million Btu/hr) relative to the distance of the top burner row to the furnace nose, or exit, (46 feet) is relatively high. This tends to indicate that there is less room above the top burner row available for placement of the OFA ports. Also, potential flame impingement on super-heater/reheater tubes may limit the amount of combustion staging and lower the NO_x reduction performance.

The bulk and upper furnace residence times can be estimated by dividing the total furnace height and the top burner row/furnace exit distance by the bulk furnace gas velocity, respectively. Residence times for completing combustion are low, thus increasing the potential for carbon burnout problems and limiting the retrofit OFA system NO_x reduction performance. However, the upper furnace residence time (approximately 1.2 seconds) is slightly longer than that of Brown Plant unit 3 (approximately 1.0 seconds).

For thermal NO_x effects, although not as critical for tangential units, both the furnace volumetric and burner zone heat release rates (22,000 Btu/hr-ft^3 and 400,000 Btu/hr-ft^2, respectively) are high for tangential units. For fuel NO_x effects, the fuel N and O/N ratio are both low for unit 2. The degree of flame interaction, evaluated by the burner heat input relative to the vertical burner spacing, though not so critical for an OFA retrofit, is high for unit 2.

Finally, the plant indicated no significant slagging problems on unit 2. This observation is supported by the intermediate to low excess air levels (20 percent). Also, the steam generation rate per furnace plan area factor (approximately 1,200 lb/hr-ft^2) is below the level indicating the potential for slagging and fouling problems (1,300 to 1,500 lb/hr-ft^2). The coal burned in unit 2 has a relatively high sulfur content (2.9 weight percent), possibly creating some corrosion or tube wastage problems for an OFA system retrofit.

It is estimated that a retrofit OFA system applied to Smith unit 2 would exhibit an intermediate NO_x reduction performance. This performance level is estimated at 15-25 percent NO_x reduction. Based on the current lack of slagging problems, small furnace height, and low residence times, OFA retrofit could be expected to exhibit intermediate NO_x reduction performance.

9.4.1.1 Natural Gas Reburning

Natural gas reburning (NGR) was assumed to be applicable at boiler 1. A NO_x emission reduction of 50 percent was assumed to be achievable with injection of 15 percent of the boiler heat input as natural gas. The natural gas and OFA would be injected in the upper furnace section. For unit 1, no furnace height data were obtained to make a judgement about the potential effect of upper furnace residence time on retrofit NGR NO_x reduction performance.

9.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700°F for coal-fired systems requires the use of a tail-end system with flue gas reheat.

For units 1-2, it was assumed that the tail-end SCR system would be used to minimize unit down times and maximize catalyst life. Boiler 1-2 flue gases would be diverted after passing through the ESPs to the reheater and through the catalyst. Hot flue gas from the reactor would be cooled by heat exchange with flue gas from the ESP before returning to the chimney. The catalytic reactors would be located beside each unit's chimney.

Table 9-14 summarizes the SCR unit retrofit difficulty and scope adjustments for boiler units 1 and 2. The retrofit factor includes access and congestion, and underground obstruction considerations. A high retrofit factor was applied to the SCR for unit 1 because of access and congestion considerations caused by the old chimney and existing flue gas ducting. The are beside unit 2 is less congested, and a low difficulty factor was assigned. However, if an FGD system is also installed, the SCR retrofit difficulty factors would be high for both units.

9.4.3 Summary of NO_x Control Costs

Table 9-15 and figure 9-9 present the annual cost of NO_x controls. The unit cost of LNC at boiler 2 was estimated to be $152 per ton of NO_x removed. The unit cost of NGR at boiler 1 was estimated to be $1,192 per ton. Application of LNC and NGR to boilers 1 and 2 reduces NO_x by 2,700 tons per year. Application of SCR would reduce NO_x emissions by 6,100 tons per year if 80 percent reduction of NO_x can be achieved at cost per ton of NO_x removed of $5,272-5,847.

TABLE 9-14. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR ELMER SMITH PLANT (August 1987 Dollars)

Item	Boiler 1	Boiler 2
Site access and congestion for SCR reactor	High	Low
SCOPE ADDER PARAMETERS		
Building demolition (1,000$)	0	0
Ductwork demolition (1,000$)	50	56
New duct length (feet)	100	250
New duct costs (1,000$)	643	2,191
New heat exchanger (1,000$)	2,434	3,345
Total scope adder costs (1000$)	3,127	5,592
Retrofit factor for SCR	1.52	1.16
General facilities (percent)	13	13

TABLE 9-15. NO_X CONTROLS COSTS FOR ELMER SMITH PLANT

NO_x Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X Reduced (tons/year)
Natural Gas Reburn	1	50	17.3	1,192	5.2	1,700
Overfire Air	2	25	2.9	152	0.1	1,000
Selective Catalytic Reduction	1	80	180.6	5,272	36.9	2,800
	2	80	126.2	5,847	16.6	3,300

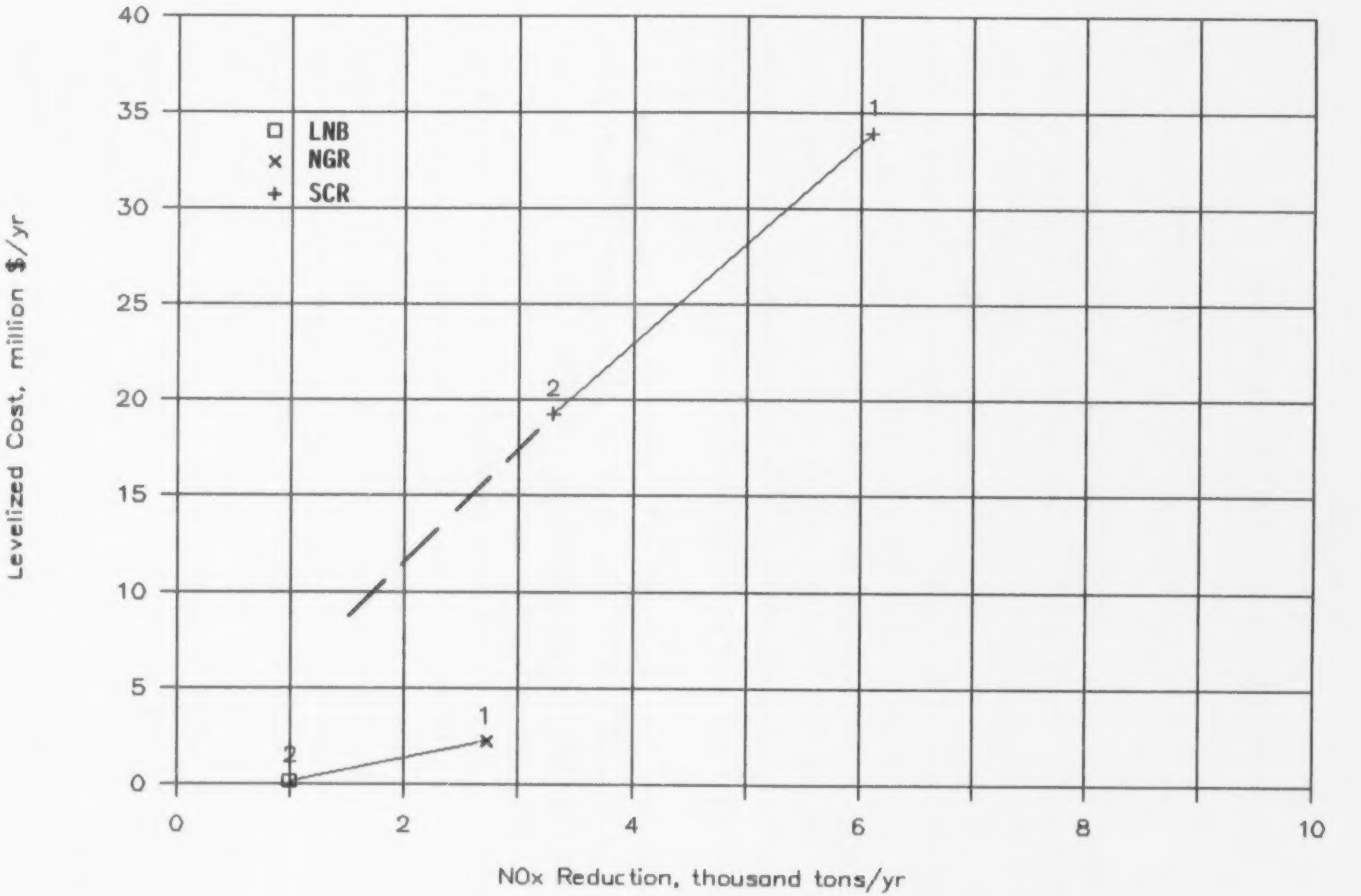

Figure 9-9. Elmer Smith NO_x controls cost versus NO_x reduction.

SECTION 10

BIG SANDY PLANT RETROFIT FACTORS AND COSTS

10.0 PLANT DESCRIPTION

The Big Sandy Plant, owned and operated by Kentucky Power Companies, is located on the western bank of the Big Sandy River fifteen miles south of the town of Ashland. The plant has two coal-fired boilers with a total net generating capacity of 1,080 MW. The plant is surrounded by forest land, with no commercial industry nearby. Figure 10-1 shows the location of the boilers, generating turbines, and other facilities.

Table 10-1 presents the key design and operational data for the plant. Boiler unit 1 net capacity is 260 MW, and unit 2 is 800 MW. Both units are pulverized coal-fired boilers with separate generator/turbine systems. Both boilers are wall-fired, dry bottom units burning a 1.2 percent sulfur bituminous coal.

Coal delivery to the plant is by truck and rail, with most shipments being received by truck due to lower cost. From the coal pile, where a 60-day supply is maintained, coal is conveyed to a bunker for unit 1 and to one of six bunkers for unit 2. Currently, the plant lacks coal blending capability. The coal is cleaned to some degree prior to delivery.

Particulate emissions at the plant are controlled by electrostatic precipitators (ESPs). The ESPs at both units have been retrofit with SO_3 conditioning equipment. Unit 1 is a single box ESP which was retrofit in 1970 and performs quite well with respect to the applicable Kentucky particulate emission standard of 0.24 $lb/10^6$ Btu (outlet emissions are 50 percent below the Kentucky standard). The unit 1 ESP collection efficiency was boosted from 95 percent to 97.4 percent with the retrofit sulfur trioxide conditioning system. Plant personnel indicated that unit 1 ESP has spare SO_3 conditioning capacity. Unit 2 has a split box ESP with outlet emissions close to the current state standard of 0.24 $lb/10^6$ BTU. Addition of SO_3 conditioning at this unit boosted the collection efficiency from 91.8 to 97.7

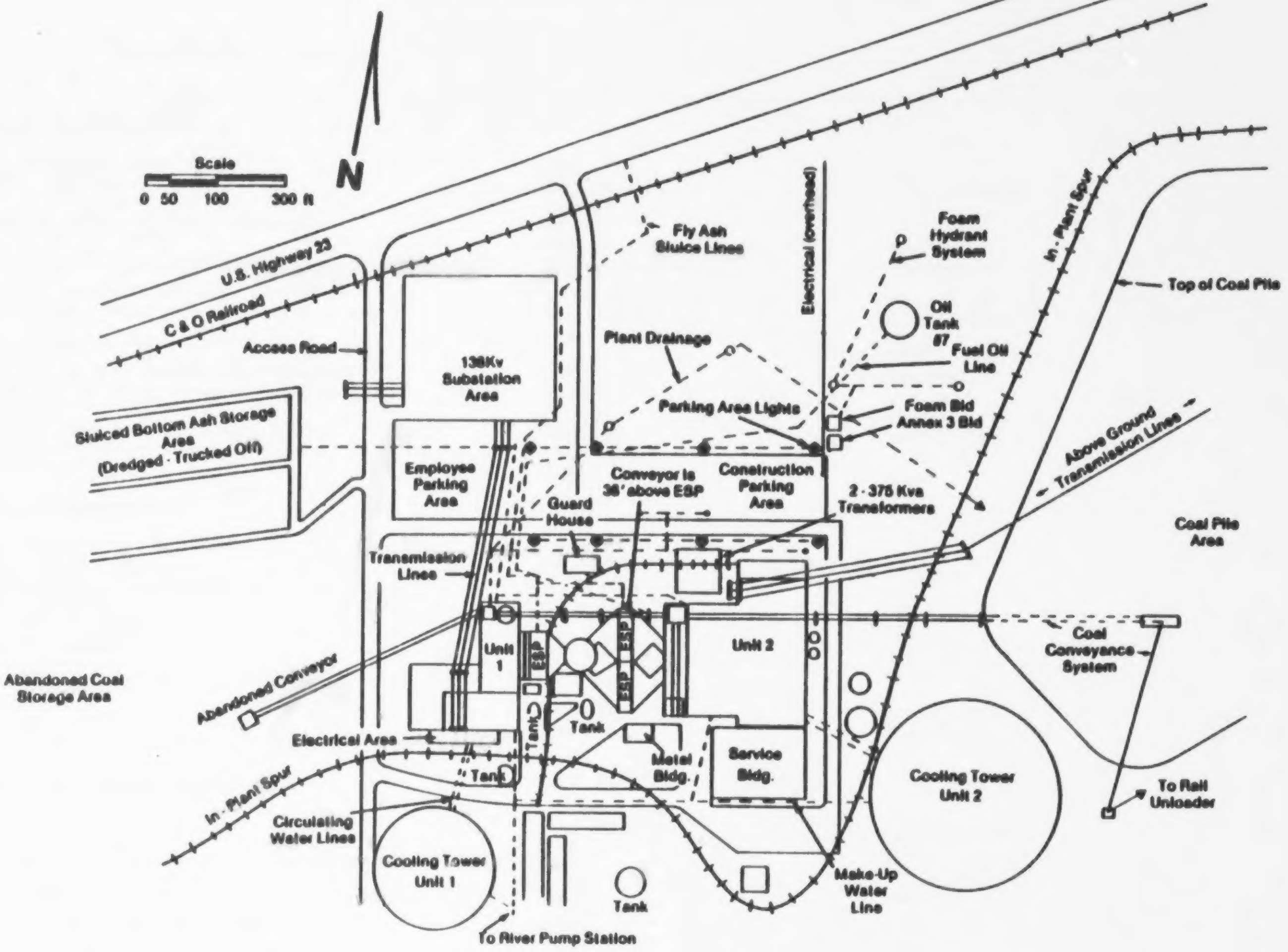

Figure 10-1. Big Sandy Plant plot plan.

TABLE 10-1. KEY DESIGN AND OPERATIONAL DATA FOR BIG SANDY PLANT

Item	Unit 1	Unit 2
BOILER AND STACK DATA		
Net generating capacity (MW)	260	800
Boiler manufacturer	Babcock & Wilcox	Foster Wheeler
Installation date	1963	1969
Capacity factor (10 year projected)	63	63
Heat rate (Btu/kW-hr)	9990	8640
Boiler type/firing type/bottom type	Opposed/wall/dry	Opposed/wall/dry
Boiler dimensions, (ft, D x W x H^a)	28 x --^{b} x --^{b}	40 x 75 --^{b}
Burner type/number of burners (# EL x #/EL)	Circular/3x6	Circular/3x12
Burner spacing (vert x horiz, ft)	--^{b}	12x9
Burner zone heat release rate (Btu/hr-ft^2)	--^{b}	483,000
Design oxygen level (percent O_2)/excess air	3.0/18	3.0/18
Draft type	Forced	Forced
Flue gas flow rate (1000 acfm @ $^{\circ}$F)	950 @ 287°F	3000 @ 350°F
Stack Size (height x diameter, feet)	825 x 28	825 x 28
Stack liner type	Steel	Steel
FUEL AND SORBENT DATA		
Coal quality^c		
Heat Content (Btu/lb)	11,620	11,620
Volatile matter (percent)	27.7	27.7
Ash (percent)	12.7	12.7
Moisture (percent)	8.2	8.2
Sulfur (percent)	1.2	1.2
Nitrogen (percent)	--^{b}	--^{b}
Coal delivery methods		
Current	Truck/Rail	Truck/Rail
Design	Truck/Rail	Truck/Rail
Likely method for sorbent delivery		
PARTICULATE CONTROL EQUIPMENT DATA		
Type of control	ESP/cold side	ESP/cold side
Installation date	1971	1969
ESP specific collection area (ft^2/10^3 acfm)	212	153
Total plate area (10^3 ft^2)	201.6	428
Emission standards (lb/10^6 Btu)	0.24	0.24
ESP Outlet Emissions (lb/10^6 Btu)^d	0.16	0.20
Design coal sulfur (percent)	0.7	1.5
Gas conditioning	Yes	Yes
Tested efficiency/design efficiency	98.3/98.5	98.3/98.5

(Continued)

TABLE 10-1. (CONTINUED)

Item	Unit 1	Unit 2
NITROGEN OXIDE CONTROL EQUIPMENT DATA		
NO_X control equipment	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA		
SO_2 control equipment	None	None
SOLID WASTE DISPOSAL DATA		
Ash transport system type		
Boiler bottom ash	Wet sluice	Wet sluice
ESP hoppers	Wet sluice	Wet sluice
Ash disposal method	Pond	Pond
Existing pond capacity	80 Years	80 Years
Estimated distance to off-site waste disposal	N/A[e]	N/A

---

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

[e] N/A = Not applicable.

percent. Plant personnel indicated that no spare SO_3 conditioning capacity exists for the unit 2 ESP.

Both unit 1 and unit 2 ESPs exhaust into a common 825 foot steel lined stack. Unit 1 originally had its own stack located on the northeast corner of the unit 1 powerhouse, but this stack is no longer used. The outlet ductwork from unit 1 ESP is routed to the combined chimney located between unit 1 and 2 ESPs.

Fly ash from both ESPs is sluiced across U. S. Highway 23 into a very large fly ash settling basin. This basin has an estimated 80-year storage capacity. Boiler bottom ash is sluiced to a different set of ash settling basins at the northwest corner of the plant. The bottom ash basins are periodically dredged, and the ash is trucked to the fly ash basin for final disposal.

10.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Big Sandy Plant include lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching, and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates developed.

10.2.1 Lime/Limestone and Lime Spray Drying FGD

10.2.1.1 Control Cases Evaluated--

Table 10-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. For L/L FGD, two control configurations were considered for these technologies at Big Sandy including (1) separate control systems for each unit and (2) a combined low capital cost control system for both units. Units 1 and 2 are co-located, and as such are good candidates for a combined FGD system. The low capital cost control system case also makes use of an optimized scrubber

TABLE 10-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR BIG SANDY PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	1.2	11,600
Boiler 2	90	1.2	35,800
LSD FGD (new baghouse)			
Boiler 1	84	1.2	10,900
Boiler 2	87	1.2	34,400
LOW COST CONTROLS			
L/LS FGD			
Boilers 1-2 combined	90	1.2	47,400

module configuration and is a limestone system using organic acids which reduce system equipment sizes.

For LSD FGD systems, two systems were evaluated, one where the existing ESPs are used to collect the fly ash and increased loading due to the spray dried solids, and one where a new baghouse is installed. For both boilers reuse of the ESPs was considered unlikely because (1) the ESPs would require significant additional plate area to achieve the current particulate emission standards, and (2) there is limited area around the existing ESPs for adding additional particulate controls. This is confirmed by plant personnel who felt it was unlikely the existing ESPs could handle the increased loading. Although costs were developed for LSD FGD with ESP reuse, only the costs for the new baghouse case are presented.

10.2.1.2 Layout of Equipment and Design Basis--

An important consideration in the development of retrofit factors and costs is the placement of the major components of the SO_2 control system at the site. Site-specific access/congestion and other factors can complicate the placement of the control equipment thereby impacting the retrofit cost. For each SO_2 control case considered, a simplified plant drawing or conceptual design is prepared which illustrates the placement of the key components of each SO_2 control system and which is used in the development of retrofit factors.

Each SO_2 control system drawing shows the major system components including: absorbers, spray dryers, ductwork, baghouses, clarifiers/vacuum filters, sorbent preparation, sorbent receiving, and storage, and FGD waste storage systems. The size of these components is a key issue at the Big Sandy station. For the L/LS FGD equipment, sorbent receiving, preparation, and storage facilities are sized based on the assumption that lime would be the sorbent of choice.

The following is a list of the drawings developed to illustrate the SO_2 control cases.

Figure Number	SO_2 Control Case Description
10-2	Separate L/LS FGD systems for units 1 and 2
10-3	Combined L/LS FGD system for units 1 and 2
10-4	Separate LSD FGD systems for units 1 and 2 (with new baghouse particulate control)

These drawings are not intended to represent the accuracy and detail associated with an engineering drawing but are approximately to scale. They were prepared from drawings supplied by the plant, sketches and measurements made during the plant visit, and photographs taken during the plant visit. These drawings and figure 10-1 were reviewed by plant personnel for accuracy and completeness.

Several key factors were considered in developing the control system designs illustrated in figures 10-2 through 10-4. All of these considerations are best satisfied by placing the majority of the control equipment in open areas to the north of the existing ESPs and stack. These rather large open areas allow somewhat conventional system layouts to be developed for most of the LSD FGD and L/LS FGD cases evaluated, although for some cases existing equipment and structures do interfere with control equipment. The site south of the stack is considered to be too congested with above and below ground interferences for placement of major components of the control systems. Also, this area is not well suited for temporary waste storage.

10.2.1.3 Scope Adjustments--

In order to retrofit control systems at Big Sandy, it was assumed that some existing equipment would be modified so costs not included in the IAPCS models were added to account for this equipment. These are referred to as scope adjustments or adders and are summarized in table 10-3 for all LSD and L/LS FGD cases evaluated.

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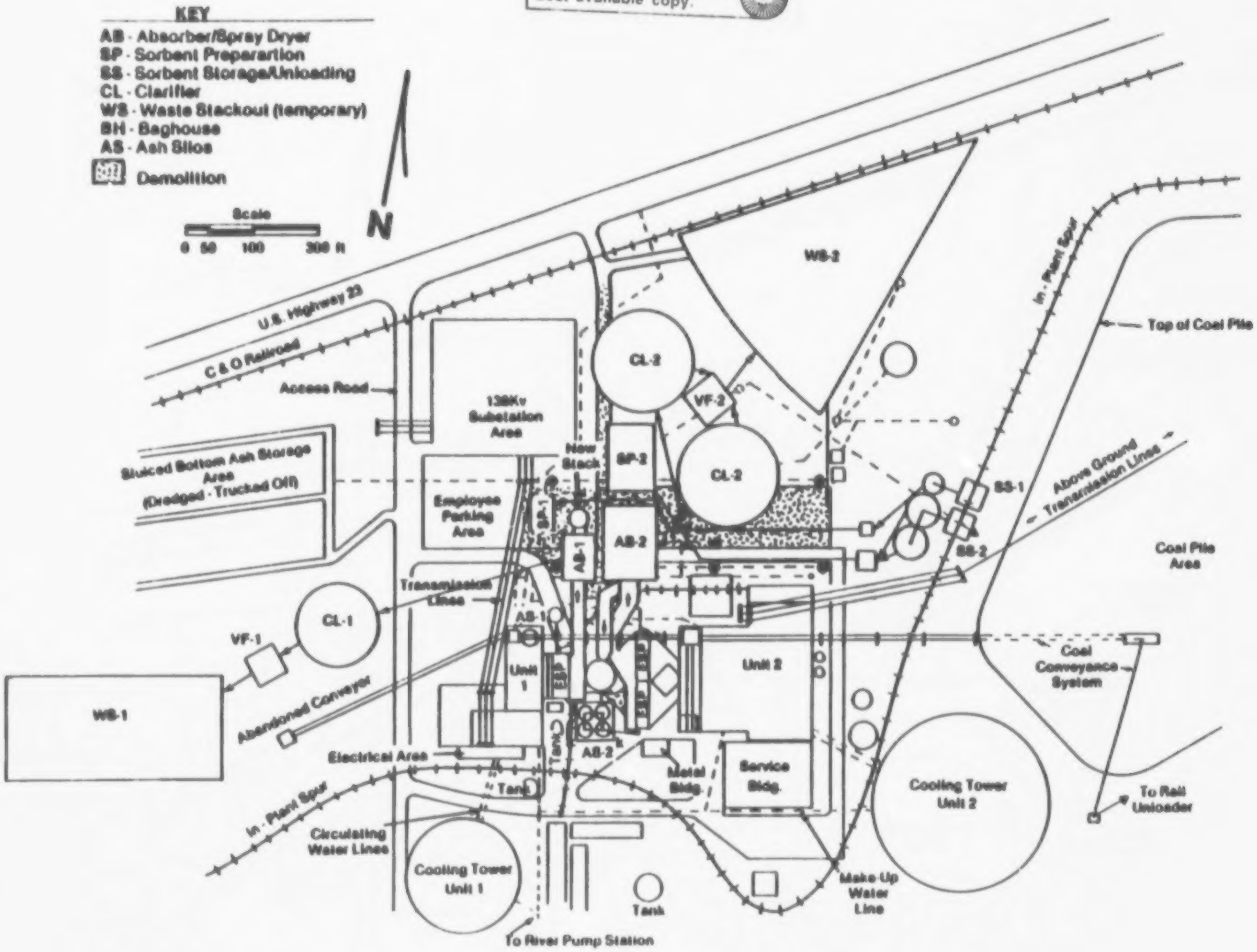

Figure 10-2. Big Sandy Plant separate L/LS FGD for units 1 and 2.

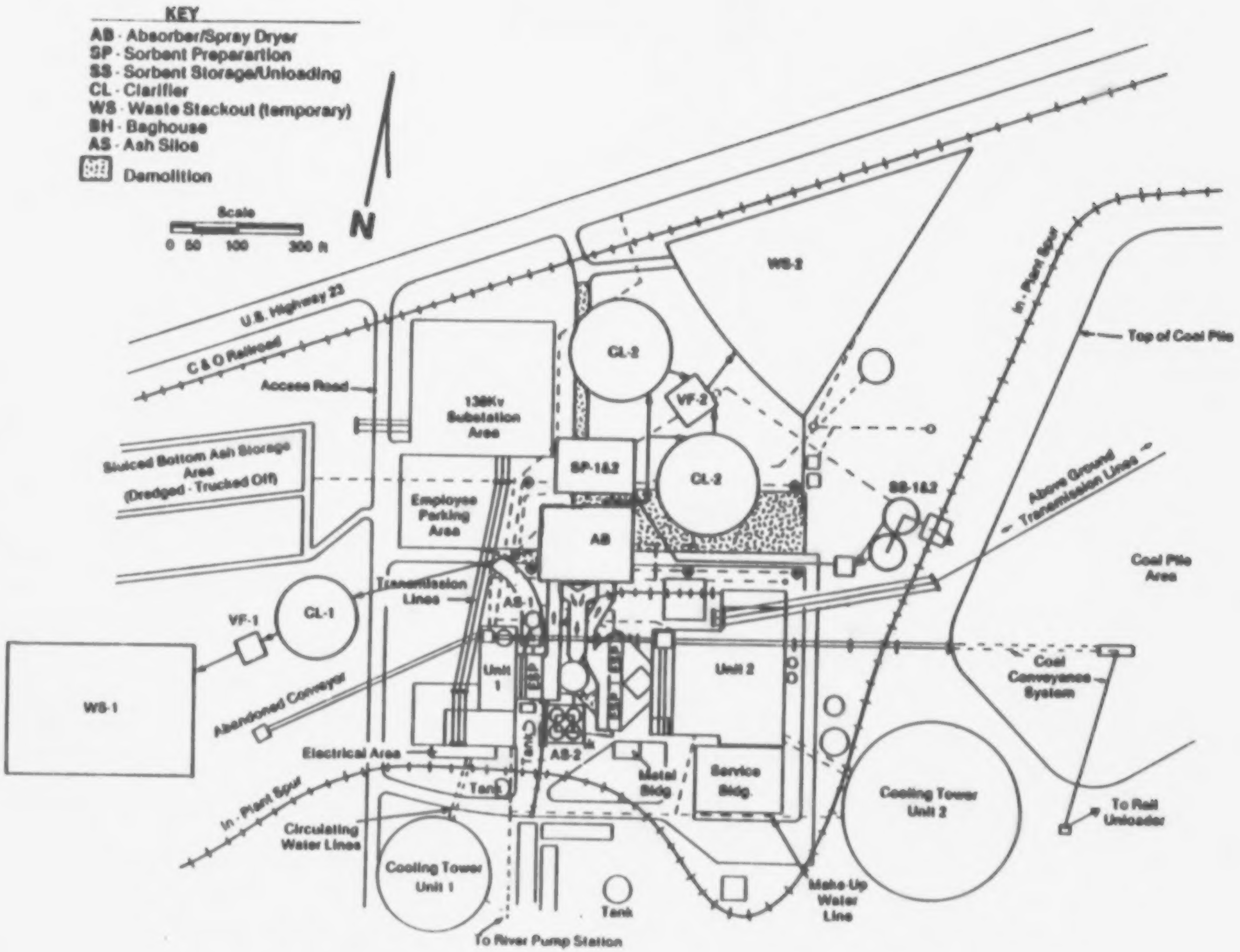

Figure 10-3. Big Sandy Plant combined L/LS FGD system for units 1 and 2.

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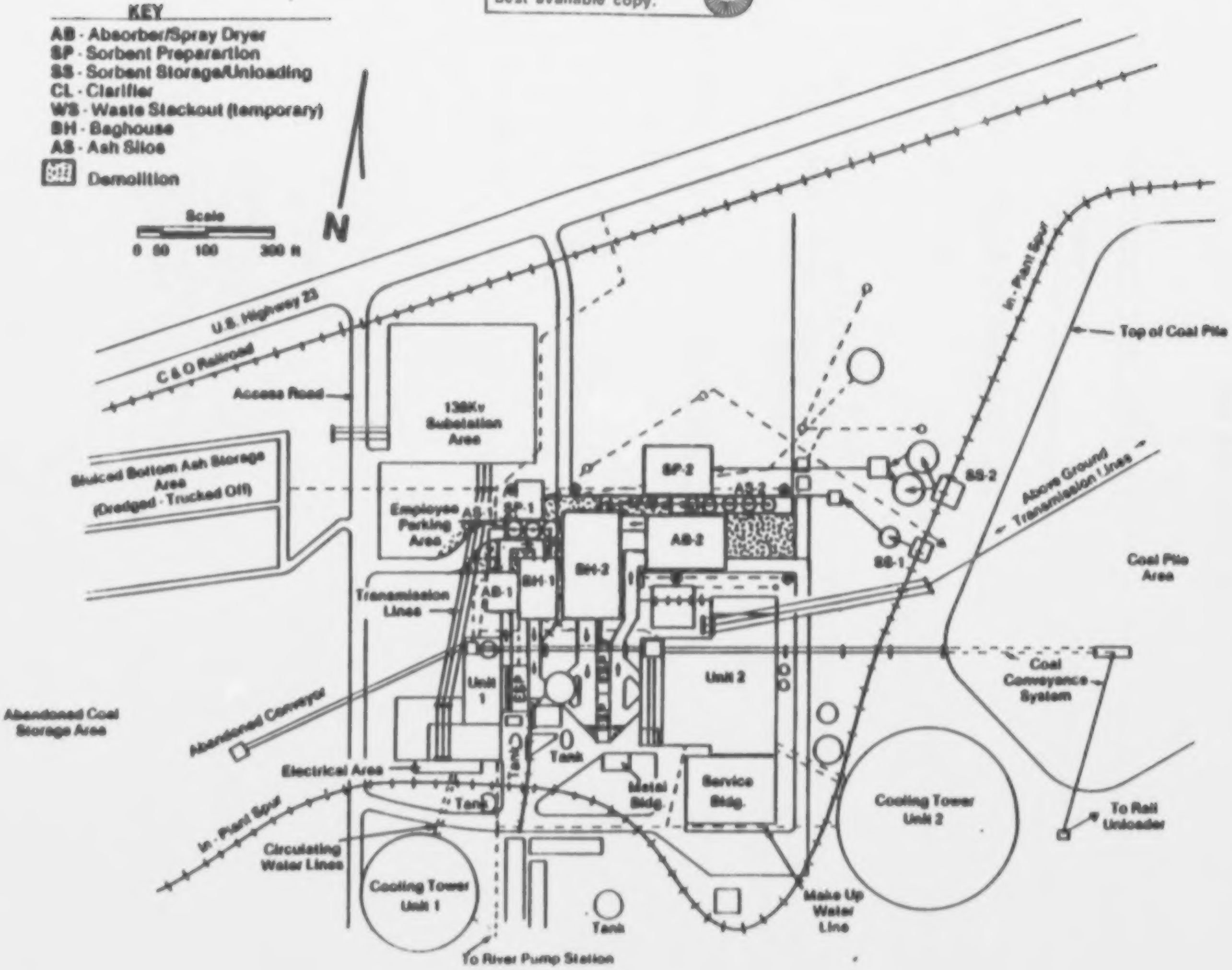

Figure 10-4. Big Sandy Plant separate LSD FGD systems for units 1 and 2 (with new baghouse particulate control).

TABLE 10-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR BIG SANDY PLANT

Scope Adjustment	Description[a]
ADJUSTMENTS APPLIED TO BOTH L/LS AND LSD FGD	
• Draft controls	Balanced draft controls were required with new SO_2 controls systems ($1.20 kW).[2]
• Guard house demolition, duct work demolition, electrical demolition, and relocation	When these items interfered with the placement of equipment, demolition and relocation costs were added ($.28/kW-$.88/kW).
ADJUSTMENTS APPLIED TO L/LS FGD ONLY	
• Stack relining	Existing stack relined to prevent corrosion. Applied for shared control systems and for unit 2 control system ($40/ft^2).
• New stack	For the individual control system on unit 1 because the cost for ducts and to reline the 800 ft. stack was greater than ($7/kW).
• Ash removal/conveyance modification	Both ESP ash systems changed from wet sluice to dry ($8.61/kW for unit 1 and $7.70/kW for unit 2). Not used when FGD waste is pumped to on-site ponds.

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

LSD FGD cases evaluated include the cost of adding a new baghouse to handle the increased loading. The retrofit cost for this baghouse is included by the IAPCS model and a scope adder is not necessary. The cost of a new stack is added to the L/LS FGD control system cost for unit 1. A new stack is added because the cost of the alternative strategy was higher (it is more costly to reline the existing 800 foot stack and route new ductwork back to this stack according to the EPRI methodology). For the combined L/LS FGD system, the reline option is used because the cost of relining is shared between both units and the cost impact on unit 1 is significantly reduced.

The cost of converting the ESP ash removal and conveyance systems for both units from a wet to a dry system is included for the L/LS FGD cases. It was assumed that the fly ash would be used for FGD sludge stabilization.

The costs for modifying the draft controls, guardhouse demolition, parking lot and relocation, and stack relining are also included and are based on EPRI guidelines. The cost to relocate the guardhouse, plant roads, and the parking area is accounted for in the general facilities cost. For all cases, general facilities factors from 5 to 10 percent were used for both units.

10.2.1.4 Location and Retrofit Factors--

Tables 10-4 and 10-5 present the location and retrofit factors used for L/LS and LSD FGD cases. Retrofit factors are site-specific constraints that account for the cost associated with the site-specific difficulty of retrofitting control equipment. These factors account for underground obstructions, site accessibility, congestion, distance to the control system (tie-in ductwork), and distance to the sorbent preparation and waste processing equipment. Table 10-6 summarizes retrofit factors for the low cost boiler case.

Table 10-7 presents the distances between process areas and flue gas handling duct distances. Tie-in ductwork length can have a significant impact on the flue gas handling retrofit cost if long tie-in ductwork distances are necessary. The systems were laid out to minimize duct length so low to moderate tie-in distances generally occur (enough duct was added so

TABLE 10-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR BIG SANDY PLANT

		RETROFIT FACTORS							
	All Units	Boiler #1				Boiler #2			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	0.98	1.13	1.15	1.00	1.30	1.06	1.05	1.00	1.11
SO_2 Removal	1.02	1.00	1.10	1.00	1.10	1.00	1.02	1.00	1.02
Flue Gas Handling	0.99	1.06	1.30	1.20	1.65	1.06	1.50	1.37	2.18
Waste Handling	1.01	1.00	1.02	1.03	1.05	1.14	1.02	1.01	1.17
General Support Equipment	0.98	1.06	1.08	1.00	1.14	1.06	1.08	1.00	1.14
SCOPE ADJUSTMENTS									
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Chimney	1.01	1.00	1.02	1.00	1.02	1.00	1.10	1.00	1.10
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			12.0				12.0		
General Facilities - %			10.0				10.0		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 10-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 10-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR BIG SANDY PLANT

		RETROFIT FACTORS							
	All Units	Boiler #1				Boiler #2			
Items	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	0.80	1.13	1.05	1.00	1.19	1.06	1.02	1.00	1.08
SO_2 Removal	0.96	1.03	1.30	1.00	1.34	1.01	1.10	1.00	1.11
Flue Gas Handling	0.82	1.03	1.10	1.42	1.61	1.03	1.30	1.45	1.94
General Support Equipment	0.81	1.06	1.08	1.00	1.14	1.06	1.08	1.00	1.14
SCOPE ADJUSTMENTS									
Baghouse	0.96	1.03	1.10	1.00	1.13	1.03	1.10	1.00	1.13
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			12.0				12.0		
General Facilities - %			5.0				10.0		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 10-7 for distance assumptions used.

[e] AGGF = Aggregate Factor.

TABLE 10-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES EVALUATED FOR BIG SANDY PLANT

	All Units	RETROFIT FACTORS			
		Boilers #1 & 2			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	0.98	1.06	1.05	1.00	1.11
SO_2 Removal	1.02	1.00	1.02	1.00	1.02
Flue Gas Handling	0.99	1.06	1.50	1.37	2.18
Waste Handling	1.01	1.14	1.02	1.01	1.17
General Support Equipment	0.98	1.06	1.08	1.00	1.14
SCOPE ADJUSTMENTS					
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00
Chimney	1.01	1.00	1.10	1.00	1.10
Demolition	1.06	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES					
Engineering - %			12.0		
General Facilities - %			10.0		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 10-7 distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 10-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR BIG SANDY PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
INDIVIDUAL CONTROLS				
L/LS FGD				
Boiler 1	295	75	100	475
Boiler 2	250	270	100	220
LSD FGD (new baghouse)				
Boiler 1	250	325	100	N/A[c]
Boiler 2	370	230	100	N/A
LSD FGD (reuse ESP)				
Boiler 1	250	240	100	N/A
Boiler 2	240	310	100	N/A
LOW COST CONTROLS				
L/LS FGD				
Boiler 1-2	260	270	100	220

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

the equipment could be located at a reasonable distance from the coal handling and other existing structures). One exception to this is the LSD FGD case evaluated for unit 2 where a new baghouse is applied. Due to the large transformers located north of the unit 2 powerhouse, unusually long duct runs were required to avoid having to relocate this key area of the plant. Since the distance from L/LS FGD absorbers is also key in developing sorbent preparation and waste handling costs, these distances are also shown on table 10-7.

An additional significant location factor for the Big Sandy plant is associated with seismic zone. The plant is near an area where moderate damage could occur in the event of an earthquake (zone 2). Because of this, equipment costs are increased to account for the cost of specialized equipment. The soils factors selected for Big Sandy are lower than the EPRI base case since soil conditions are more desirable. Available data indicate that the soil at the Big Sandy station has a good local bearing capacity (4000 lb/ft^2). The material cost and labor productivity index also has a significant impact on the location factor. The value used for Kentucky is 1.06.

Underground obstruction factors were selected based on the conceptual design drawings in figures 10-2 through 10-5. These drawings show the location of major underground obstructions at the plant including: plant drainage systems, ash sluice lines, circulating water lines, hydrant systems, water mains, fuel lines, and more. Whenever a process area is located over an obstruction shown in the drawing, the appropriate underground obstruction factor is selected based on EPRI guidelines. For example, the sorbent preparation areas were located over sluice lines so medium to high factors were used. In general, medium to high underground obstruction factors were used.

Access/congestion factors can have a major impact on retrofit cost. In most cases medium to high access congestion factors were used for the flue gas handling area on both units. These medium to high values were selected in part because of the ductwork close proximity to the coal conveyance system and supports and because of the congestion around the ESP stack area. Higher factors were generally used for unit 2 because of the additional complication of having to route ductwork around the boilers air inlet ductwork located at the ESP inlets (this duct passes between the split box).

Medium access/congestion factors were generally used for the SO_2 removal process area on unit 1, due to overhead obstructions on two sides and proximity to access roads and employee parking areas. Other process areas for unit 1 had relatively free access with little congestion, and low access congestion factors were selected.

10.2.1.5 Overall Retrofit Factors and Costs--

Table 10-8 presents the overall retrofit factors and costs for all FGD cases. The range of costs represent the different L/LS FGD process options examined: limestone conventional and organic acid enhanced, and lime slurry conventional and MgO enhanced. The costs shown were generated from the IAPCS model after adding the retrofit difficulty factor and scope adder costs which generates the capital and operating costs of FGD.

Figures 10-5 and 10-6 summarize the plant level costs of installing L/LS and LSD FGD. The data point labeled low cost shows the impact of economies-of-scale when combining process areas. The application of L/LS FGD would reduce plant level SO_2 emissions by 47,400 tons per year assuming 90 percent emission reduction. For application of LSD FGD, the estimated emission reduction is 49,300 tons per year if replacement fabric filters are installed.

10.2.2 Coal Switching/Blending

Table 10-9 presents the 1985 coal analysis used at Big Sandy and the alternative coal used to evaluate the impact of coal switching. The switch coal was a low-sulfur Kentucky coal having a 0.7 percent sulfur content.

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

TABLE 10-8. L/LS AND LSD FGD COSTS FOR BIG SANDY PLANT (August 1987 Dollars)

Case Description	Overall Retrofit Factor	IAPCS Retrofit Costs[a]		
		Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.50	230.4-268.7	2,018-2,263	16.4-18.4
Boiler 2	1.54	161.4-189.5	1,416-1,625	11.5-13.2
LSD FGD (new baghouse)[b]				
Boiler 1	1.88	261.2	1,953	14.8
Boiler 2	1.75	215.4	1,507	11.8
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1 & 2	1.53	117.4	962	7.8

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] Includes impact of new baghouse.

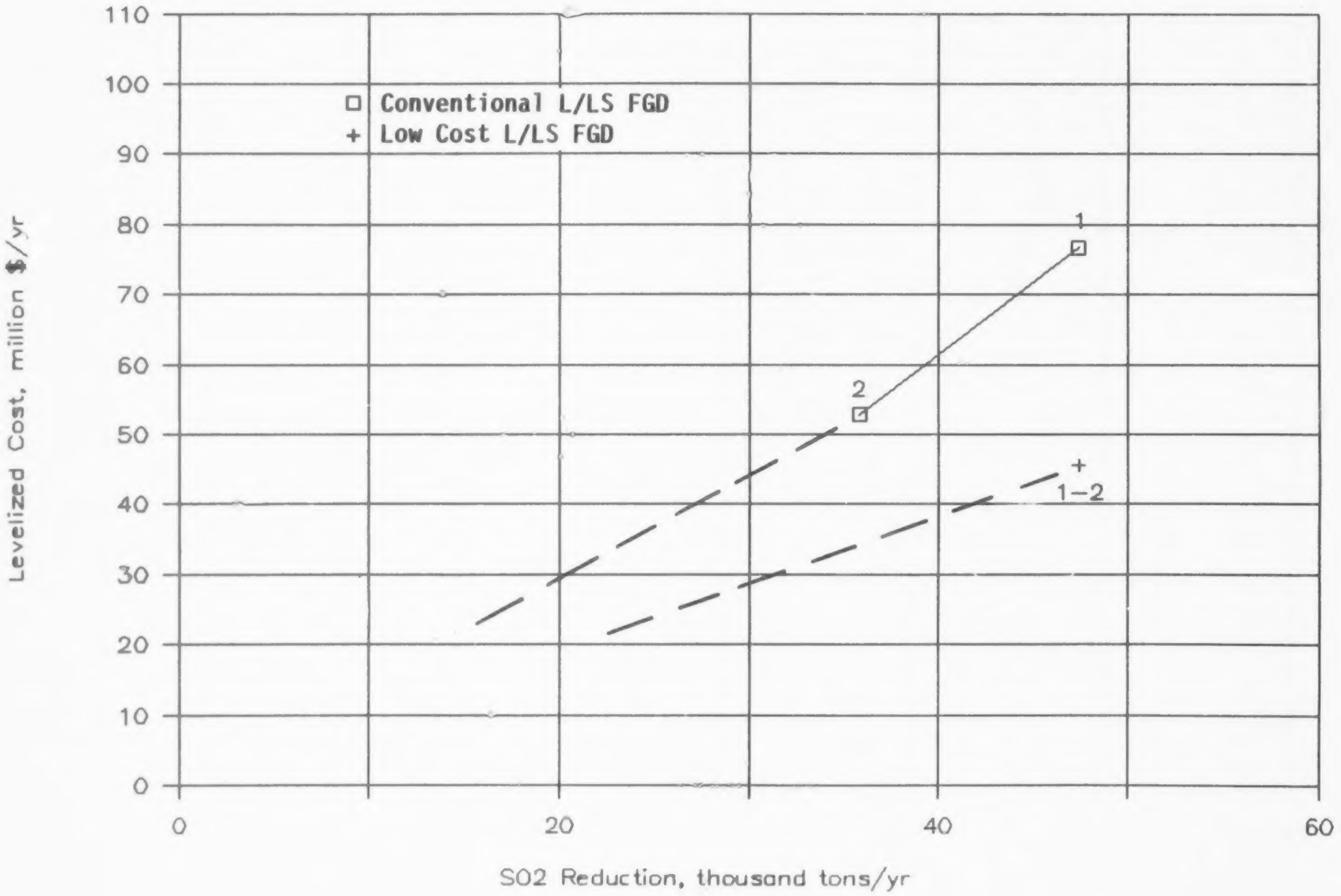

Figure 10-5. Big Sandy Plant L/LS cost versus SO_2 reduction.

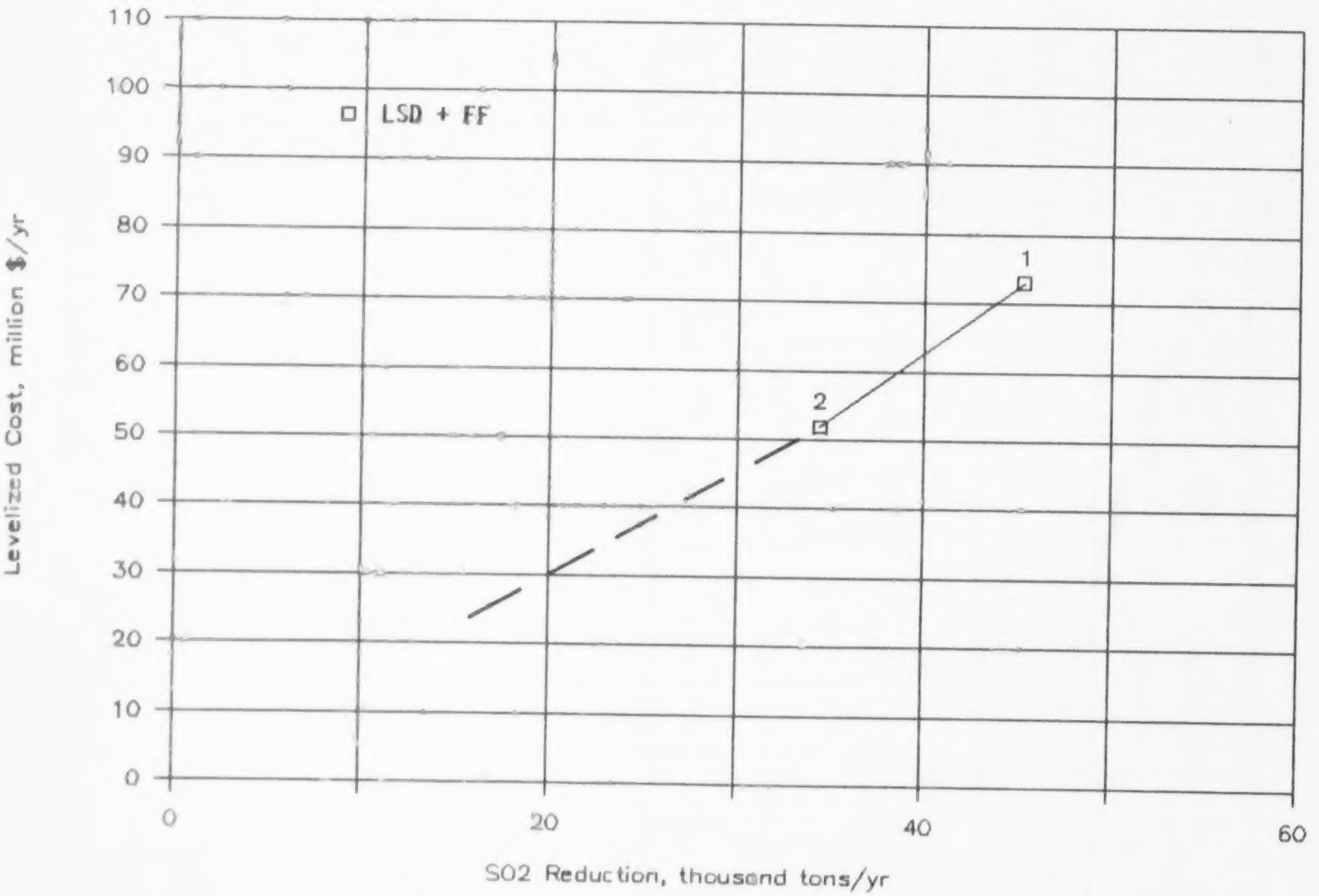

Figure 10-6. Big Sandy Plant lime spray dryer FGD cost versus SO_2 reduction.

TABLE 10-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR BIG SANDY PLANT

Item	Existing Coal		Switch Coal		Cleaned Coal	
	Boiler		Boiler		Boiler	
	1	2	1	2	1	2
COAL PARAMETERS						
Percent Sulfur	1.2	1.2	0.7	0.7	0.8	0.8
Percent Ash	12.7	12.7	8.7	8.7	4.6	4.6
Btu Per Pound	11,622	11,622	12,741	12,741	13,100	13,100
ESP PARAMETERS						
Existing/ Needed SCA[a]	212	158	269	287	269	287

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

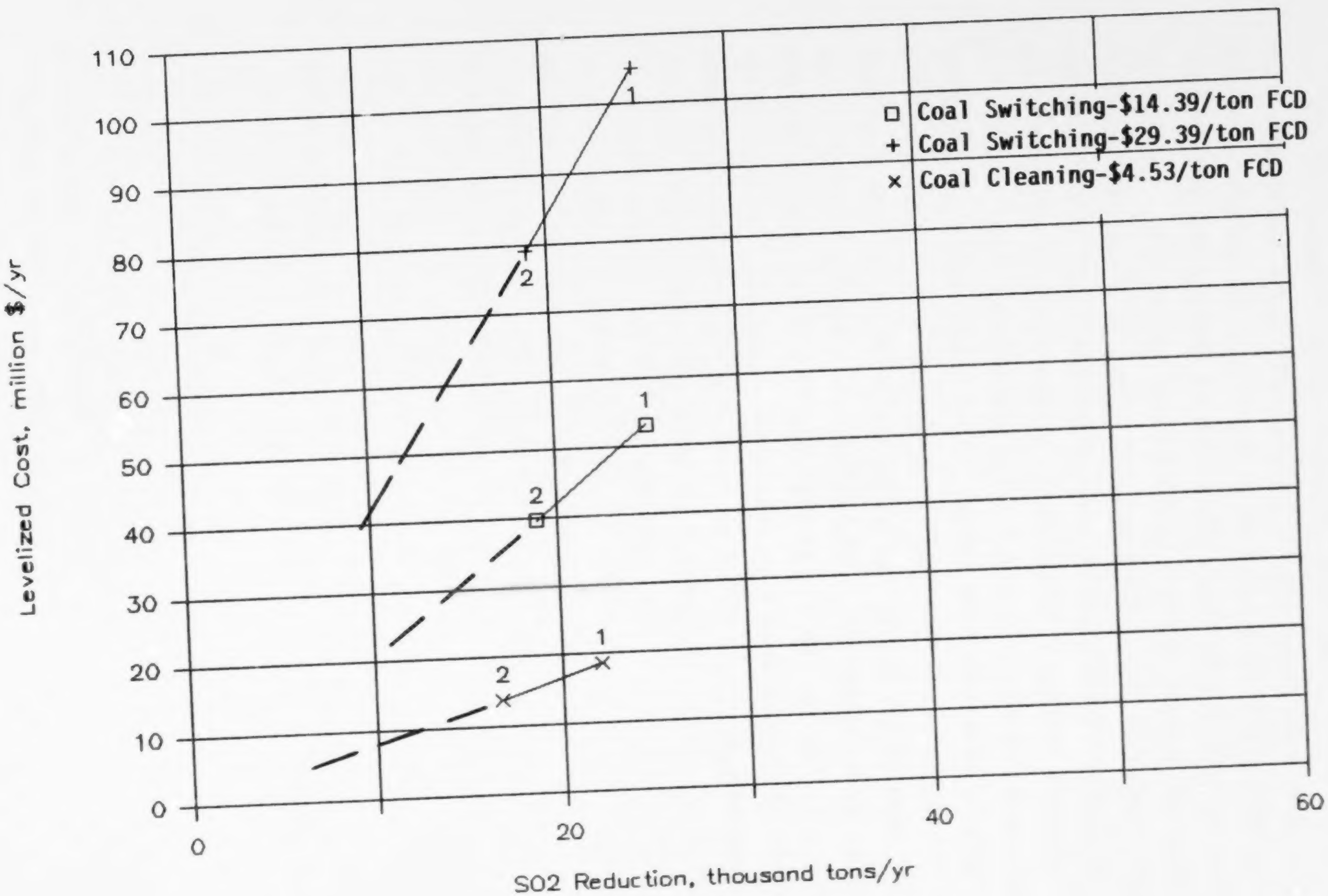

Figure 10-7. Big Sandy coal switching/cleaning costs versus SO_2 reduction.

ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. For boilers 1-2 with SO_3 conditioning, a 27-82 percent increase in the existing ESPs would be needed for low-sulfur coal service. However, because the benefits of SO_3 conditioning are highly variable, the predicted cost for ESP plate area increase should be viewed as a minimum estimate.

Figure 10-7 presents the plant level cost and emission reduction for switching to a low-sulfur coal. Curves were generated to show the impact of different fuel cost differentials. The lower curve represents a 1985 levelized fuel price differential of $14.39 per ton between the existing coal and an eastern Kentucky low-sulfur coal. The upper curve shows the impact of additional fuel price differentials of $15 per ton over the 1985 fuel price differential. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 10-10. Approximately 25,000 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.0 pound per million BTU SO_2 emission rate. Comments from the plant personnel indicated that the cost of ESP upgrade was estimated to be 10-15 million dollars for unit 1 and 30 to 50 million dollars for unit 2. Costs for additional ESP plate area and SO_3 conditioning have been included, although both ESPs already have SO_3 conditioning systems. However, the ESP for unit 2 would likely have to be replaced. This would add 40 to 50 million dollars to the capital costs, resulting in a rate of over $400 per ton of SO_2 removed. Adding plate to unit 1 would also be difficult, and replacement would cost $15 to $20 million dollars in capital. No costs have been included, however, for new coal receiving and blending facilities.

10.2.3 Physical Coal Cleaning

Physical coal cleaning was evaluated using coal characteristics for a similar medium-sulfur coal. Coal cleaning costs were estimated using a cleaned option in the IAPCS model which has cleaning costs based on a model developed by TVA. It was assumed that the coal would be cleaned at the mine,

TABLE 10-10. COAL SWITCHING COSTS FOR BIG SANDY PLANT
(August 1987 Dollars)

		@ \$14.39/ton FCD		@ \$29.39/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
1	6,100	2,235	9.6	4,313	18.5
2	18,900	2,226	9.5	4,304	18.4

and no refuse disposal would be required at the plant. The cleaned coal parameters were input into the IAPCS model to estimate performance impacts on the ESPs. Cost estimates for each boiler are shown in table 10-11. Figure 10-7 also presents the results of the cost model runs for physical coal cleaning.

These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal. The costs do include the estimated increase in coal cost for the cleaning operation (\$4.53 per ton). Cleaning the coal reduces the plant SO_2 emissions by 22,100 tons/yr. As discussed under coal switching, these costs do not include replacement of the unit 1 and 2 ESPs.

TABLE 10-11. PHYSICAL COAL CLEANING COSTS FOR BIG SANDY PLANT
(August 1987 Dollars)

Boiler	SO_2 Reductions (tons per year)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
1	5,400	899	3.4
2	16,700	824	3.1

10.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. The following control technologies were examined: furnace sorbent injection (FSI), duct spray drying (DSD), and retrofit of fluidized bed combustion (FBC) and coal gasification (CG). The following discussion presents the retrofit issues and cost/performance estimates developed.

10.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. Many retrofit costs consequently are built into the base case design and costs. The retrofit factors developed for these technologies include scope adders not included in the developers' assumptions. These include base costs such as particulate control equipment upgrading, additional ductwork, ductwork demolition, and rail repair. Basic assumptions and cost adjustments made for FSI and DSD are presented in table 10-12.

10.3.1.1 Furnace Sorbent Injection--

Furnace sorbent injection was evaluated for both units at the Big Sandy station. However, since both ESPs would likely require significant additional ESP plate area to be added in a high access/congestion area, the costs developed for FSI using the IAPCS model would understate the cost of this technology. For this reason, these costs were not presented.

10.3.1.2 Duct Spray Drying --

Duct Spray Drying using a slurried calcium based sorbent was evaluated for retrofit at boilers 1 and 2. The existing particulate control systems for units 1 and 2 would require significant additional plate area. And for both units, flue gas residence time between the air heater outlet and ESP

TABLE 10-12. SCOPE ADJUSTMENTS FOR DSD AT BIG SANDY PLANT

Item	Boiler 1	Boiler 2
BASIC ASSUMPTIONS		
Approximate access/congestion rank	Medium	Medium
Can the existing ESP be upgraded?	No	No
Was a new baghouse evaluated for DSD?	Yes	Yes
Distance to final waste disposal (miles)	1	1
SCOPE ADDERS		
Install dry ash handling system[a]	N/A[b]	N/A
New Stack	No	No
Additional duct work (ft)[b]	300	450
Electrical relocation	300	300
Building demo area (ft^2)	300	300
ADDER COSTS AND RETROFIT FACTOR SUMMARY		
Scope adder costs for new baghouse (10^3 \$)[c]	2,458	7,935
Scope adder costs for ESP reuse (10^3 \$)[c]	N/A	N/A
Baghouse retrofit difficulty factor	1.13	1.13
ESP upgrade retrofit difficulty factor (for plate area addition)	N/A	N/A

[a] Not applicable when a new baghouse is installed.

[b] N/A = Not applicable.

[c] June 1985 dollars.

inlet is insufficient to obtain adequate droplet drying and good SO_2 removal. Only a new baghouse case was evaluated for both units.

Retrofit costs for the duct sorbent injection technologies at the Big Sandy station primarily focus on developing sorbent preparation, sorbent injection, and waste handling process areas. Additionally, the costs of scope adders not included in the base cost were determined, including demolition/relocation of existing equipment and buildings.

10.3.1.3 Overall Retrofit Factors and Costs--

Table 10-13 summarizes the overall retrofit factors and costs for DSD. Figure 10-8 presents the cost of retrofitting DSD on boilers 1-2 versus the plant level SO_2 reductions achieved. For duct spray drying with a new fabric filter, plant-wide SO_2 emissions are reduced by 35,500 tons per year at a cost of $1302 to $1684 per ton of SO_2 removed.

10.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

Boiler units 1 and 2 were evaluated for retrofit of FGC and CG. Unit 1 is a a medium-size unit (260 MW) with good heat rate (9,990 Btu/kwhr), high capacity factor (63 percent), and moderate service life (24 years). Based on these parameters, it would be classified as a marginal candidate for FBC/CG retrofit. However, replacement of the existing ESP for coal switching/cleaning likely would be needed. FGD and DSD retrofit difficulty is moderate to high, which would enhance the potential for FBC/CG retrofit. Since unit 2 is an 800 MW base load unit and has been in service less than twenty years, FBC was assumed not to be applicable.

10.4 NO_x CONTROL TECHNOLOGIES

NO_x controls evaluated at the Big Sandy Plant include low NO_x combustion and selective catalytic reduction. Low NO_x burners (LNB) were evaluated for boiler units 1-2 because both boilers are of a dry bottom, opposed wall-fired furnace design. The site-specific factors affecting the performance of

TABLE 10-13. RETROFIT COSTS FOR DSD FOR BIG SANDY PLANT
(August 1987 Dollars)

Case Description	IAPCS Captial Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Duct Spray Drying (new fabric filter)				
Boiler 1	152.5	10.0	1,684	8,600
Boiler 2	130.2	7.9	1,302	26,900

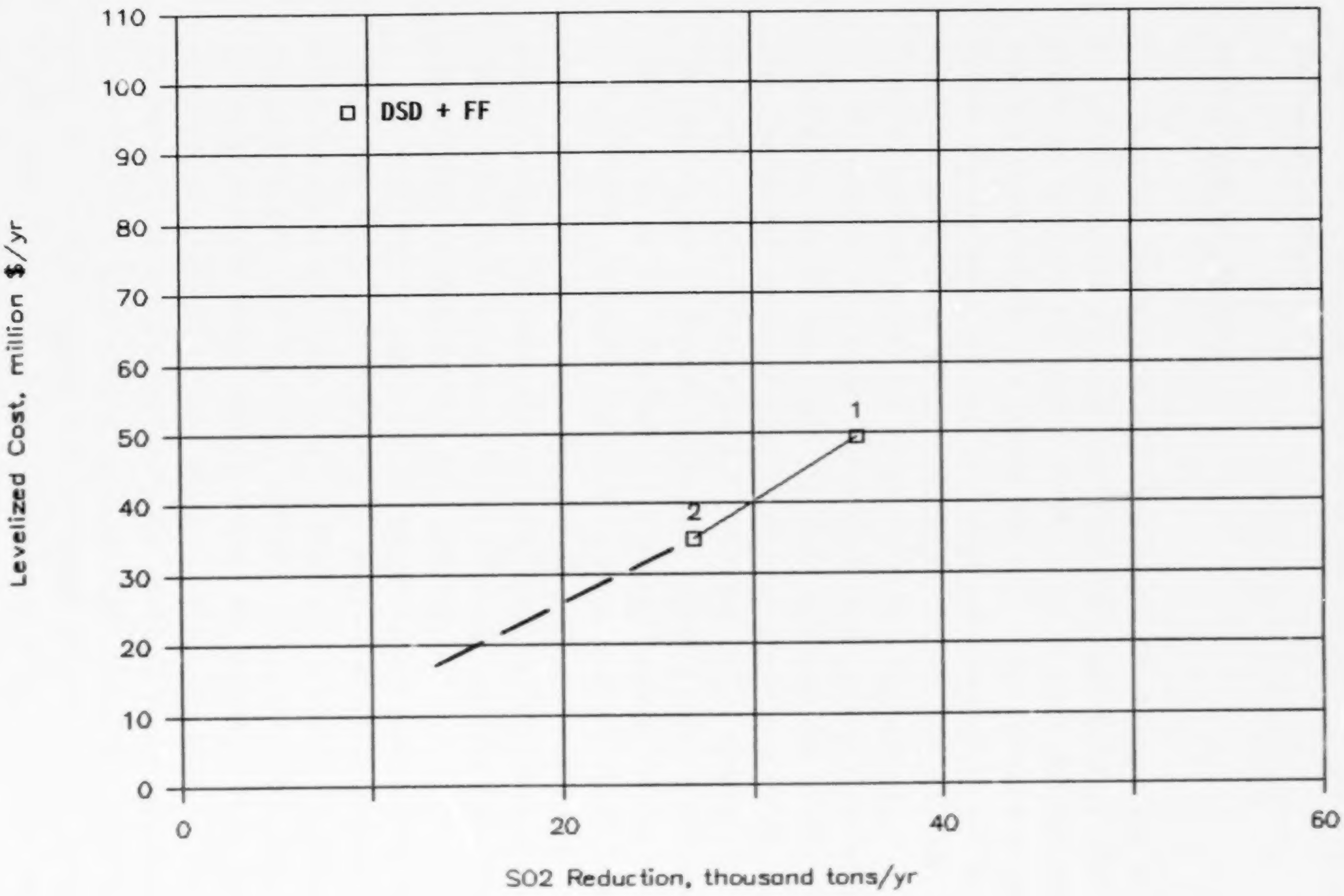

Figure 10-8. Big Sandy Plant FSI/DSD cost versus SO_2 reduction.

retrofit NO_x combustion controls at the two boilers are discussed in the following sections.

10.4.1 Low NO_x Burners

Detailed drawings clearly showing all the furnace and boiler equipment layouts/dimensions were not available for these boilers. The only critical dimension obtained for unit 1 is the furnace depth and for unit 2, the furnace depth, width, and burner spacing. Thus, furnace height, nose to top burner row distance, volume, and residence times could not be used in the NO_x reduction performance factor evaluation. Also, fuel nitrogen and oxygen contents were not available to evaluate fuel NO_x effects.

For unit 1, the burner heat input (approximately 160 million Btu/hr) relative to the furnace depth (28 feet) was high for a wall-fired unit. The plant personnel indicated that there were slagging problems associated with this unit. This observation was confirmed by the moderate excess air level (18 percent) at which unit 1 operates. Unit 1 burns a relatively low sulfur coal (1.2 percent). Although the slagging tendency of the coal should not limit retrofit LNB performance, it appears that the small furnace depth could create some rear wall flame impingement problems in a retrofit application. Balancing these factors, without additional boiler/furnace/coal information, the NO_x reduction performance level of a LNB retrofit was estimated to be intermediate, a 30-40 percent NO_x reduction.

Unit 2, with a significantly larger rating than unit 1, had a lower burner heat input (approximately 195 million Btu/hr) relative to the furnace depth (40 feet) than does unit 1. However, it was still relatively high compared to the other Kentucky and Ohio study wall-fired units. Also, with the furnace width being somewhat narrow the estimated bulk furnace gas velocity was about 60 ft/sec, which is relatively high for wall-fired units. The burner heat input relative to the vertical burner spacing was moderate. The burner zone heat release rate was high. Considering these factors, along with the same non-slagging coal as burned in unit 1, the performance level of a LNB retrofit for unit 2 was estimated to be 30-40 percent NO_x reduction, an intermediate performance level.

10.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700°F for coal-fired systems require flue gas by-pass of the economizer or use a tail-end system with flue gas reheat.

For units 1 and 2, it was assumed that the tail-end SCR system would be used to minimize unit down times due to the high access/congestion around the economizer/ESP sections. Boiler flue gases would be diverted after passing through the ESPs to a reheater and through the catalyst. Hot flue gas from the reactor would be cooled by the flue gas heat exchange in the preheater before returning to the chimney. The catalytic reactors would be located beside each unit's ESP and near the chimney.

Table 10-14 summarizes the SCR unit retrofit difficulty and scope adjustments for boiler units 1-2. The retrofit factor includes access and congestion, and underground obstruction considerations. A medium retrofit factor was applied to the SCR costs at unit 1 because of access and congestion considerations caused by the coal handling facilities and tanks. The area beside unit 2 is less congested, and a low difficulty factor was assigned. However, if an FGD system is also installed, the SCR retrofit difficulty factor would be high for both units.

10.4.3 Summary of NO_x Control Costs

Table 10-15 and figure 10-9 present the annual cost of NO_x controls. The unit cost of LNB at boiler 1 and 2 was estimated to be $281 and $144 per ton of NO_x removed. Application of LNB at both boilers would reduce NO_x by 9,170 tons per year assuming a 35 percent NO_x reduction at each boiler. The plant provided LNB capital cost estimates which were two to five times higher than those estimated by IAPCS. Capital cost estimates provided by the plant for unit 1 and 2 were $24/kW and $30/kW, respectively. Specific cost assumptions were not provided, and an analysis of cost differences was not conducted. Application of SCR would reduce NO_x emissions by 21,100 tons per year if 80 percent reduction can be achieved, at a cost of $3474-4161 per ton of NO_x removed.

TABLE 10-14. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR BIG SANDY PLANT
(August 1987 Dollars)

Item	Boiler 1	Boiler 2
Site access and congestion for SCR reactor	Medium	Low
SCOPE ADDER PARAMETERS		
Building demolition (1,000$)	0	59
Ductwork demolition (1,000$)	59	132
New duct length (feet)	500	550
New duct costs (1,000$)	4,572	9,385
New heat exchanger (1,000$)	3,494	6,626
Total scope adder costs (1,000$)	8,125	16,202
Retrofit factor for SCR	1.34	1.16
General facilities (percent)	17	25

TABLE 10-15. NO_X CONTROLS COSTS FOR BIG SANDY PLANT (August 1987 Dollars)

NO_x Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X Reduced (tons/year)
Low NO_x Burner	1	35	12.2[a]	281	0.4	2,400
	2	35	6.2[b]	144	0.2	6,930
Selective Catalytic Reduction	1	80	181.5	4,161	15.0	5,200
	2	80	131.1	3,474	12.5	15,900

[a] Plant provided cost estimate of $24/kW.

[b] Plant provided cost estimate of $30/kW.

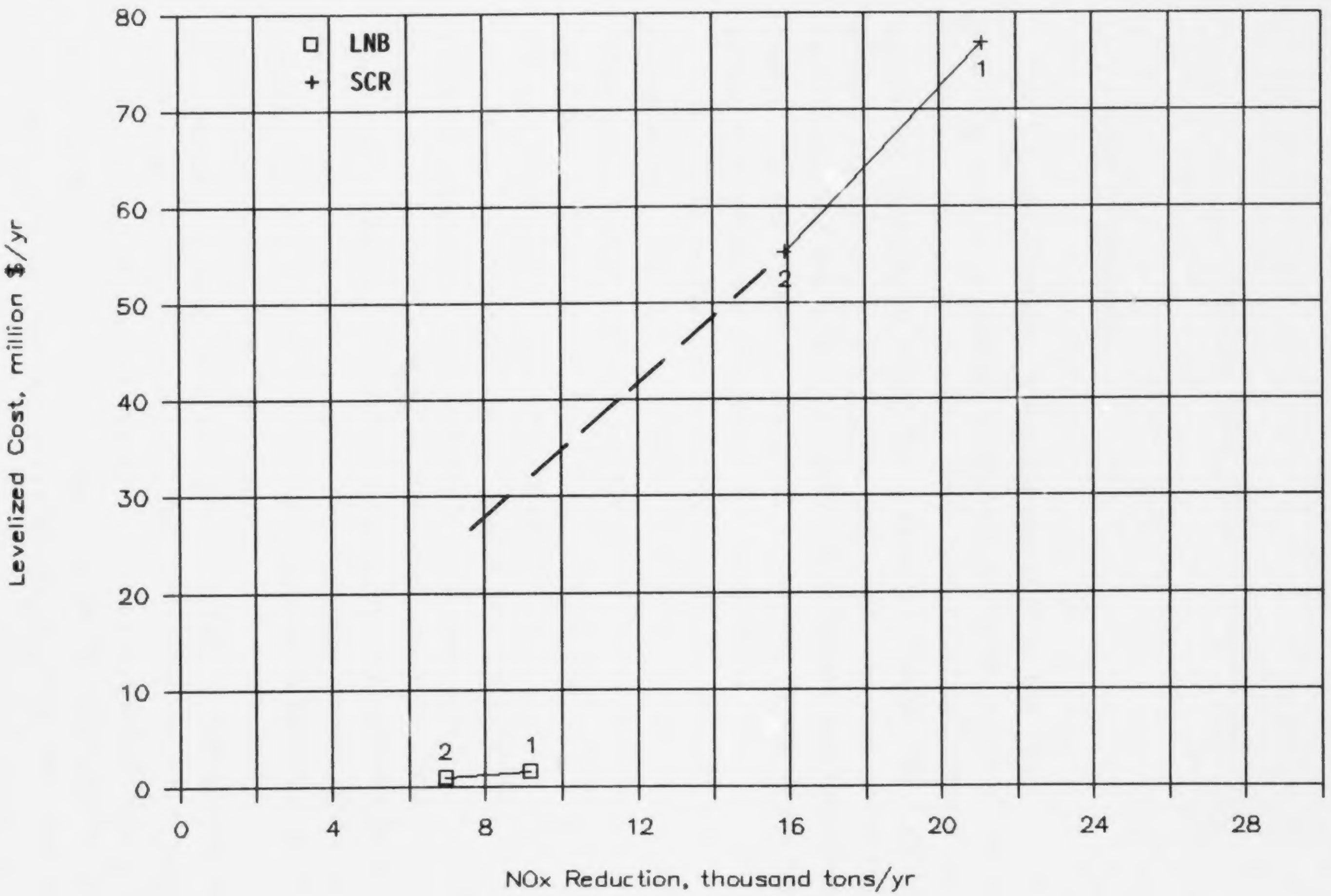

Figure 10-9. Big Sandy NO_x controls cost versus NO_x reduction.

SECTION 11

PARADISE PLANT RETROFIT FACTORS AND COSTS

11.1 PLANT DESCRIPTION

The Paradise Plant, owned and operated by the Tennessee Valley Authority (TVA), is located in western Kentucky, south of the town of Owensboro. The plant contains three coal-fired boilers and has a total net generating capacity of 2,422 MW. Figure 11-1 shows the location of the primary facilities, including the coal yard, the coal preparation facilities, and the powerhouse with FGD scrubbers and hyperbolic cooling towers. To the northeast the plant is bounded by the Green River, which serves as a primary water source for operations.

The plant receives 4 to 5 million tons of coal per year primarily from nearby mines. The coal is cleaned on-site to remove sulfur and ash, with a large area of land south of the powerhouse being devoted to coal cleaning and waste disposal operations (coal cleaning waste, bottom slag disposal, fly ash disposal, and FGD waste disposal).

Table 11-1 presents the key design and operational data for the existing equipment. Boiler units 1 and 2 each generate up to 663 MW, while unit 3 produces 1,096 MW. The steam generators for units 1 and 2 were furnished by Babcock and Wilcox Company and are cyclone-fired furnaces. Units 1 and 2 are each equipped with fourteen 10 feet diameter radial-type cyclone burners. Units 1 and 2 were changed to balanced draft in 1983 when they were retrofit with limestone FGD.

The unit 3 steam generator was furnished by Babcock and Wilcox Company and is the largest cyclone-fired unit with super-critical pressure constructed in the United States. The steam generator has a single balanced draft furnace and is fired by twenty-three 10 feet diameter radial-type cyclones. The cyclones are installed on the front and rear furnace walls in rows of two.

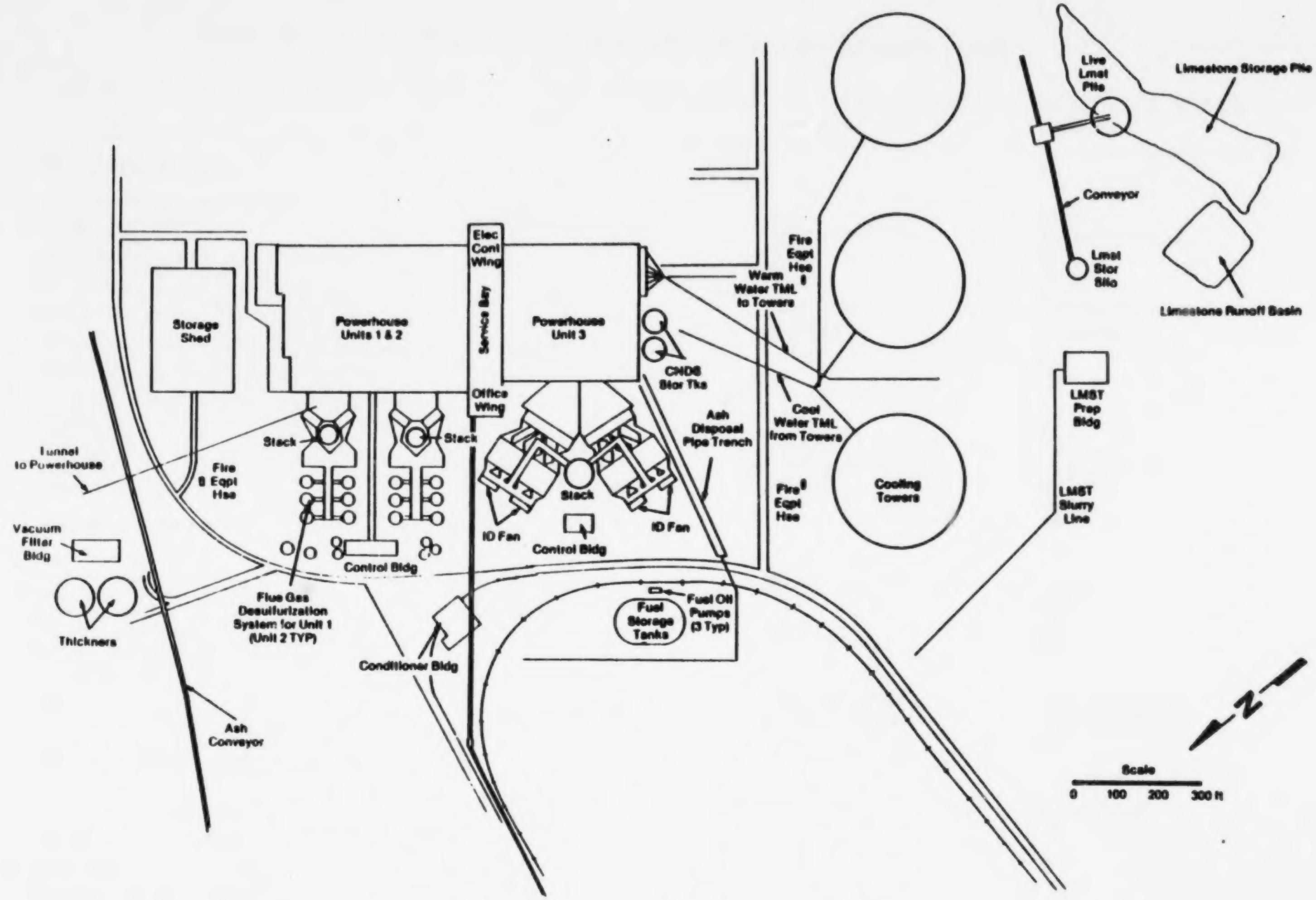

Figure 11-1. Paradise plant plot plan.

TABLE 11-1. KEY DESIGN AND OPERATIONAL DATA FOR PARADISE PLANT

Item	Boiler 1	Boiler 2	Boiler 3
BOILER AND STACK DATA			
Net generating capacity (MW)	663	663	1,096
Boiler manufacturer	Babcock & Wilcox	Babcock & Wilcox	Babcock & Wilcox
Installation date	1963	1963	1970
Capacity factor (10 year projected)	43	31	20
Heat rate (Btu/kW-hr)	9,941	9,980	10,074
Boiler type/firing type/bottom type	Cyclone/wet	Cyclone/wet	Cyclone/wet
Boiler dimensions, (ft, D x W x H[a])	32x63x163	32x63x163	33x96x160
Burner type/number of burners (# EL x #/EL)	--[b]/14	--[b]/14	2/12
Burner spacing (vert x horiz, ft)	--[b]	--[b]	--[b]
Burner zone heat release rate (Btu/hr-ft^2)	--[b]	--[b]	--[b]
Excess air (percent)	16	20	20
Draft type	Balanced	Balanced	Balanced
Flue gas flow rate (1000 acfm @ °F)	1,790 @ 290°F	1,790 @ 290°F	3,850 @ 286 °F
Stack size (height x diameter, feet)	600 x 26	600 x 26	800 x 27
Stack liner type	Lined	Lined	Unlined
FUEL AND SORBENT DATA			
Coal quality[c]			
Heat content (Btu/lb)	11,700	11,700	11,800
Volatile matter (percent)	28.9	29.3	29.3
Ash (percent)	8.2	7.0	6.8
Moisture (percent)	9.4	9.4	9.4
Sulfur (percent)	2.7	2.7	2.7
Coal delivery methods			
Current	Truck/rail/barge	Truck/rail/barge	Truck/rail/barge
Design	Truck/rail/barge	Truck/rail/barge	Truck/rail/barge
Likely method for sorbent delivery	Rail	Rail	Rail
PARTICULATE CONTROL EQUIPMENT DATA			
Type of control	ESP/cold side	ESP/cold side	ESP/cold side
New/retrofit installation	1967	1967	1969
ESP specific collection area (ft^2/10^3 acfm)	117	117	345
Total plate area (10^3 ft^2)	238	238	1,138
Emission standards (lb/10^6 Btu)	0.11	0.11	0.11
ESP outlet emissions (lb/10^6 Btu)[d]	0.09	0.06	0.03
Design coal Sulfur (percent)	2.5	2.5	2.0
Gas conditioning	None	None	None
Tested efficiency/design efficiency	95.2/98.0	96.7/98.0	98.4/99.6

(Continued)

TABLE 11-1. (CONTINUED)

Item	Boiler 1	Boiler 2	Boiler 3
NITROGEN OXIDE CONTROL EQUIPMENT DATA			
NO_X control equipment	None	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA			
SO_2 control equipment	Limestone scrubber	Limestone scrubber	None
Installation date	1983	1983	
SOLID WASTE DISPOSAL DATA			
Ash transport system type			
Boiler bottom ash	Wet sluice	Wet sluice	Wet sluice
ESP hoppers	Wet sluice	Wet sluice	Wet sluice
Ash disposal method	Pond	Pond	Pond

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

The plant location was selected to take advantage of low cost coal produced in nearby mining operations. The coal is delivered to the plant by both off-highway 100-ton trucks, and on-highway 25 and 30-ton trucks into three ground level receiving hoppers with a capacity of 2,000 tons each. A barge unloading facility is also available. Three reciprocating feeders feed the coal from the truck receiving hoppers onto three belts, rated at 1,000 tons per hour each which discharge into a rotary Bradford breaker.

The plant is required by the Clean Air Act to comply with a Kentucky sulfur dioxide (SO_2) emission standard of 3.1 $lb/10^6$ Btu. An SO_2 emissions limitation of 0.9 $lb/10^6$ Btu on units 1 and 2 is being met by burning washed coal and flue gas scrubbing. An SO_2 limit of 5.7 $lb/10^6$ Btu on unit 3 is being met by burning washed coal only.

Figure 11-2 shows a simplified process flow diagram of the Paradise coal cleaning plant. Heavy-media preparation of the coal removes 30-40 percent of the pyrite sulfur fraction and leaves the other two fractions undisturbed. In general, the plant contains four 500 tons per hour (TPH) modules and each module has three circuits:

Coarse circuit: Heavy-media vessel type, 3" x 3/8", 400 TPH max, 300 TPH nominal;
Intermediate circuit: Heavy-media cyclone type, 3/8" x 28 mesh, 200 TPH max, 160 TPH nominal; and
Fine circuit: Primary and secondary hydrocyclones, froth flotation, 28 mesh x 0, 75 TPH max, 40 TPH nominal.

The coal preparation plant has the capability of washing all of the coal burned at Paradise. The barge unloading facilities enhance selection of raw coals to be washed and provide the flexibility of bringing in lower sulfur coals.

Particulate emissions from all three boilers are controlled with electrostatic precipitators (ESPs), and each is served by a separate ESP and stack. ESPs for units 1 and 2 are identical, and both were installed in 1967. The specific collection areas (SCAs) are relatively low (117 $ft^2/10^3$ acfm) compared to unit 3. Tested removal efficiency for both ESPs on units

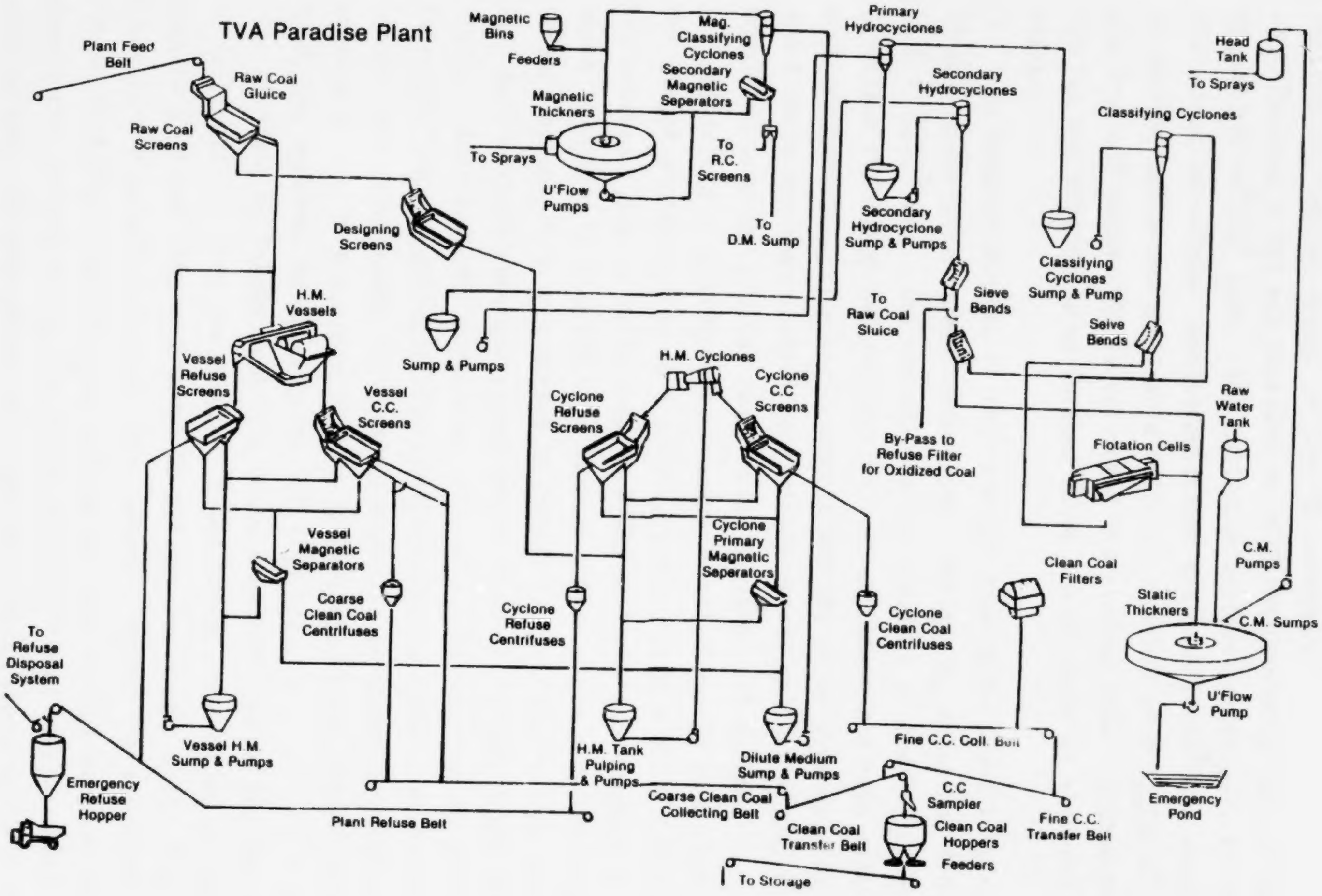

Figure 11-2. Paradise Plant simplified flow diagram.

1 and 2 is between 95 and 97 percent, but it should be noted that additional particulate removal occurs in the FGD scrubbers.

The unit 3 ESP was upgraded in 1980 and currently the collector has an SCA of 345 $ft^2/10^3$ acfm. The collector performs quite well as indicated by the outlet emissions. Outlet emissions are 0.03 $lb/10^6$ Btu which is 73 percent below the applicable emission standard of 0.11 $lb/10^6$ Btu. Fly ash from all three ESPs is collected and sluiced from the powerhouse area to the fly ash disposal area located about 1 mile south of the unit 3 ESP and stack.

One hundred percent of the flue gas from units 1 and 2 is scrubbed via forced oxidation limestone technology. Outlet SO_2 emissions from both units is 0.9 $lb/10^6$ Btu. The overall process consists of the following: (1) limestone receiving and preparation, (2) scrubbers and main control room near the boilers, (3) waste treatment and (4) waste storage. Both units 1 and 2 share the same sorbent receiving/preparation facilities, waste storage area, and scrubber control room. Unit 3 has no FGD system.

Limestone is delivered by truck and rail directly to a receiving hopper for direct processing or to a stockout pile. From a 5,000-ton storage silo the crushed stone is pulverized in 3 wet ball mills to produce a slurry which is pumped to the additive storage tanks in the scrubber area. This 40 percent by weight slurry makeup is pumped to the recycle tank associated with each venturi/absorber vessel where it is thoroughly mixed with the slurry return from the scrubbers. For each individual unit, boiler flue gas is taken from the outlet of the existing electrostatic precipitators into a common duct which feeds six venturi/absorbers arranged in parallel. A minimum of two to a maximum of five venturi/absorbers, depending on boiler load, are required to desulfurize the flue gas.

Although no longer used, the waste treatment system has two thickeners to settle solids from the absorber bleed stream, and vacuum filters to produce a filter cake with about 80 percent solids for waste disposal. However, air oxidation headers were retrofit within the absorbers (i.e., forced oxidation) resulting in calcium sulfate ($CaSO_4$) waste which is easily dewatered. Consequently, the spent absorber liquid is now pumped to a holding tank and then directly to gypsum stacking ponds south of the powerhouse.

11.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Paradise plant include lime/limestone wet scrubbing with forced oxidation (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates.

11.2.1 Lime/Limestone and Lime Spray Drying FGD

11.2.1.1 Control Cases Evaluated--

Table 11-2 lists the control cases evaluated for lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying flue gas desulfurization (LSD FGD). All cases are based on all units continuing to burn cleaned coal from the on-site coal cleaning plant and the continued use of limestone as an FGD sorbent.

In this section, L/LS FGD costs and factors are determined for units 1 and 2, even though these two units currently have these controls. Retrofit costs are determined for these boilers so that actual costs incurred for installation of these systems can be compared with the costs determined by using the EPRI guidelines and IAPCS cost models. The same L/LS FGD process option that currently exists at the plant is used as the basis for determining retrofit factors and costs for L/LS FGD on units 1 and 2 (limestone FGD with forced oxidation). It is also assumed that since forced oxidation is used on units 1 and 2 it would likely be applied to unit 3 because (1) the technology is already tried and tested at Paradise and (2) some existing facilities may be shared with unit 3 thus reducing the control cost (e.g. lime storage, waste disposal/conveyance, etc.). Costs for conventional limestone and lime FGD are not presented.

Finally, LSD FGD is evaluated for unit 3 but not for units 1 or 2 since both units 1 and 2 have L/LS FGD systems. In the LSD FGD case evaluated for unit 3 it is estimated that the existing ESP will likely be able to handle the increased loading due to spray drying with little or no modification (recall the unit 3 ESP has an SCA of 345 $ft^2/10^3$ acfm). Therefore, a new

TABLE 11-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR PARADISE PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Removed (tons per year)
INDIVIDUAL CONTROLS			
Forced Oxidation FGD			
Boiler 1	90	2.8	38,300
Boiler 2	90	2.8	38,300
Boiler 3	90	2.8	63,300
LSD (reuse ESP)			
Boiler 3	76	2.8	53,700

replacement baghouse would likely not be required and thus was not evaluated for unit 3.

SO_2 removal efficiency for L/LS FGD is assumed to be 90 percent. Removal efficiency for LSD FGD was estimated to be 76 percent when the existing ESP is reused. The LSD FGD removal efficiency is based on the flue gas temperature and 10 percent SO_2 removal in the ESP.

11.2.1.2 Layout of Equipment and Design Basis--

Layout of FGD equipment is an important consideration in the development of retrofit factors and costs, since site-specific access/congestion and other factors can complicate equipment placement, thereby impacting cost. Simplified plant drawings or conceptual designs have been prepared to illustrate component placement.

Existing layouts are used as the basis for developing retrofit factors for both units 1 and 2. Existing unit 1 and 2 receiving and storage areas were assumed to be expanded for unit 3. For the forced oxidation system, the sizes of the FGD process areas for units 1 and 2 were used as the basis for unit 3. The following is a list of the drawings developed to illustrate the SO_2 control cases:

Figure Number	FGD Control Case Description
Figure 11-3	Limestone FGD with forced oxidation for units 1, 2, and 3.
Figure 11-4	Lime spray drying FGD for unit 3 with reuse of existing ESP.

These drawings are not intended to represent the accuracy and detail associated with an engineering drawing but are approximately to scale. They were prepared from drawings supplied, sketches and measurements, and,

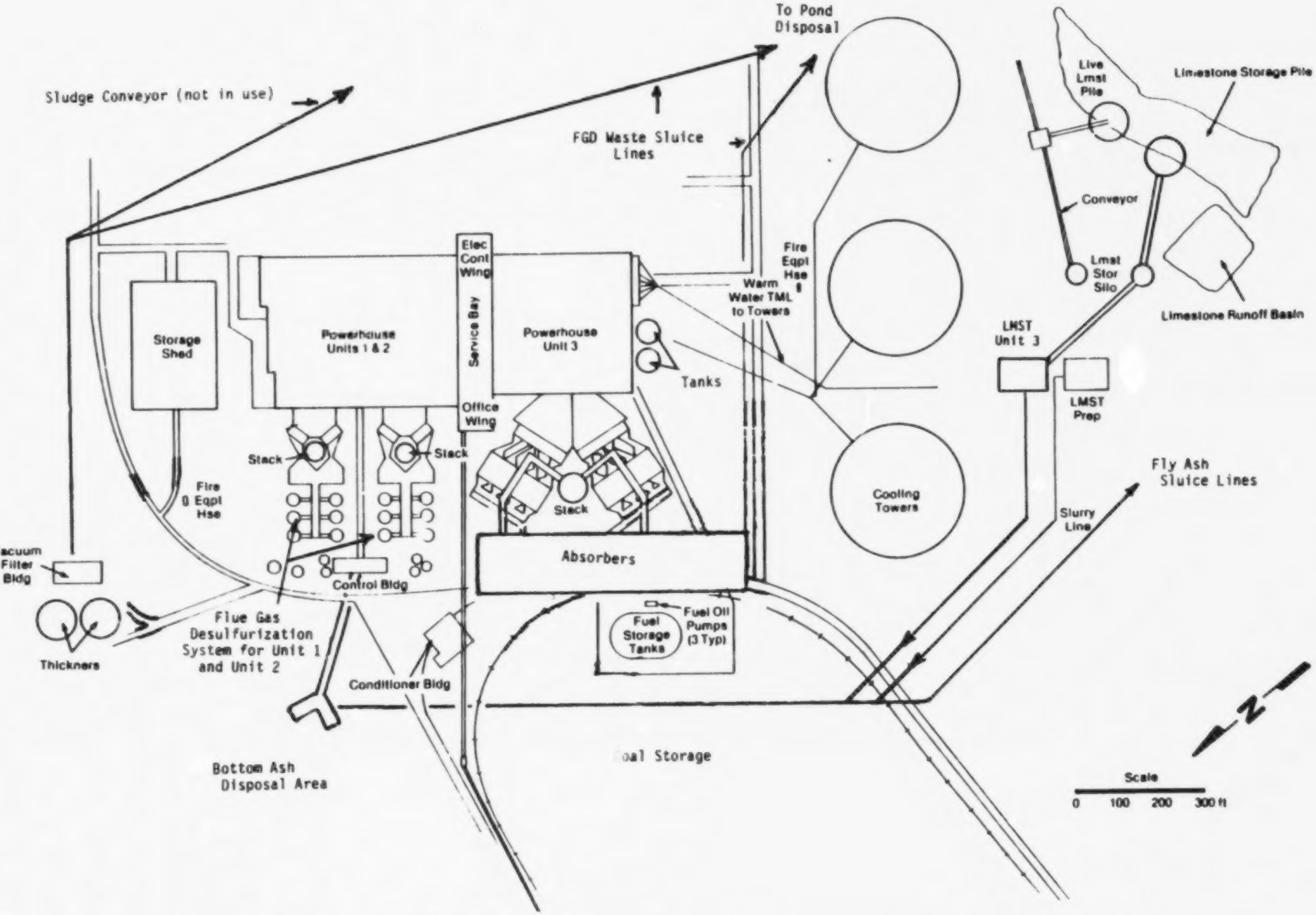

Figure 11-3. Paradise Plant limestone FGD with forced oxidation for units 1-3.

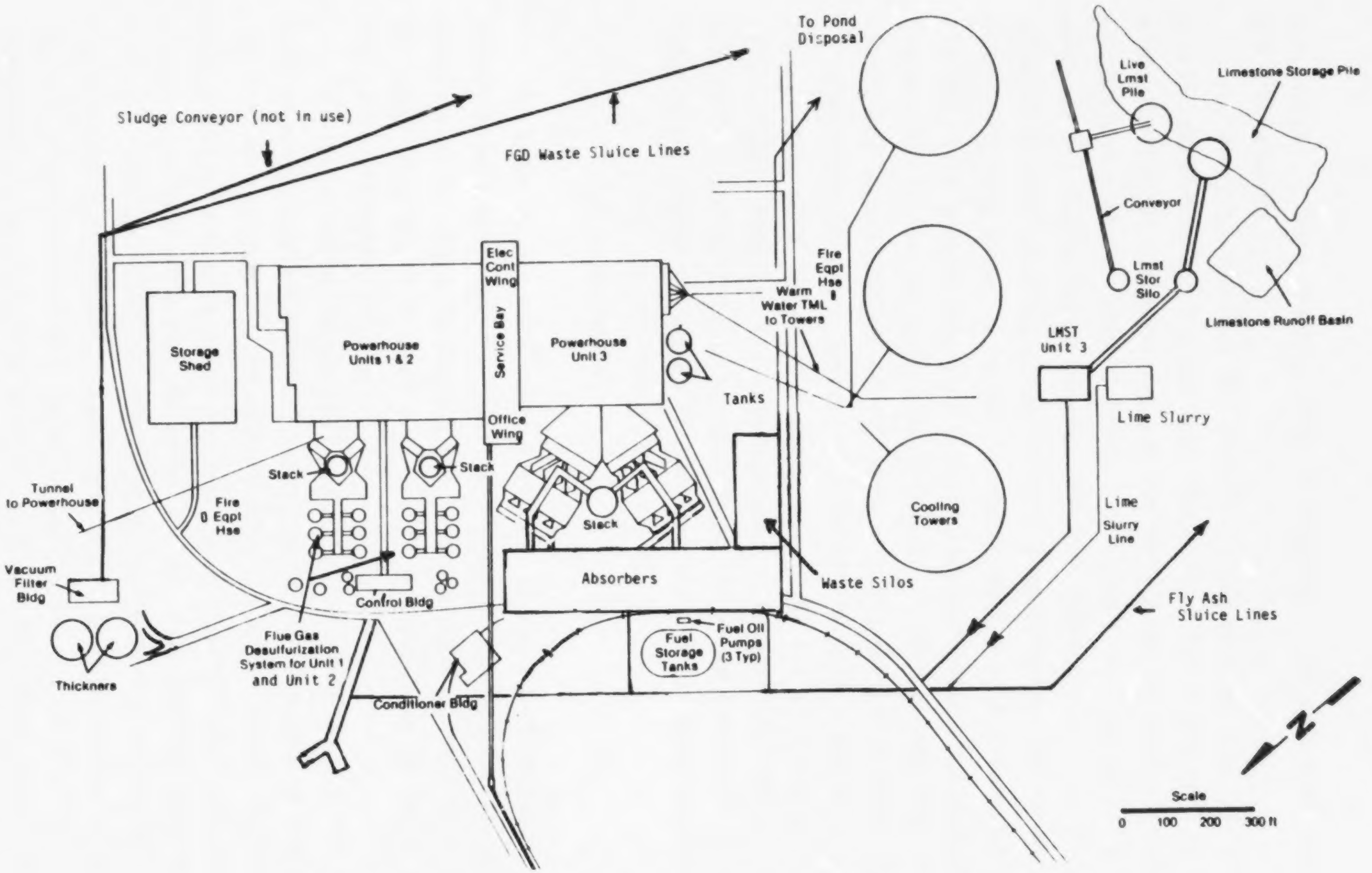

Figure 11-4. Paradise Plant lime spray FGD for unit 3.

photographs. These drawings were reviewed by plant personnel for accuracy and completeness.

For the L/LS FGD case for unit 3, it was assumed that the existing sorbent receiving and storage area for units 1 and 2 was used by unit 3. Also, the sorbent preparation area for unit 3 was located near the sorbent preparation area for units 1 and 2. By doing this, the unit 3 preparation area was (1) conveniently located near the limestone storage pile and (2) able to utilize existing sorbent slurry line trenches and raceways thus allowing slurry pipes to be easily routed to the unit 3 absorber area. For LSD FGD, lime sorbent was used also to locate sorbent receiving storage, and preparation in the existing limestone area. Instead, the lime sorbent system was located closer to its point of use; the spray dryer chamber area.

The waste handling system for L/LS FGD on unit 3 was not located in the same area as that for units 1 and 2. South of the unit 3 powerhouse would be a suitable location for this equipment. Compared to the location used for units 1 and 2, this location reduces the waste transport distance between the clarifier/vacuum filter area and the ultimate disposal site.

11.2.1.3 Scope Adjustments--

In order to retrofit control systems at the Paradise station, some existing equipment must be modified and costs not included in the IAPCS cost models must be added to account for this equipment. These are referred to as scope adjustments or cost adders and are summarized in table 11-3 for all FGD cases evaluated.

The cost for balanced draft controls are added for all FGD systems to help prevent negative pressure surges in the furnace due to the addition of SO_2 control equipment. The cost to demolish and relocate the ESP control room building for unit 3 and to relocate the electrical lines and cable trays associated with that building are added to the FGD cases evaluated for unit 3. This building interferes with the placement of L/LS FGD absorbers and LSD FGD spray dryers. Some sorbent sluice line piping for units 1 and 2 must be relocated in order to build the L/LS FGD absorbers for unit 3. Furthermore, specific data was not available regarding the building, electrical, and piping demolition/relocation costs for the FGD retrofit on

TABLE 11-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR PARADISE PLANT

Scope Adjustment	Description[a]
• Modify draft controls	Balanced draft controls were required with all SO_2 controls on all three units ($1.20/kW).
• Building demolition, relocation, and duct work demolition[b]	Demolition of unit 3 ESP control room for L/LS and LSD FGD. Demolition of 400 feet of unit 3 ductwork for L/LS and 520 feet for LSD FGD.
• Electrical/piping demolition and relocation	For L/LS and LSD FGD, 650 feet of conduit and 200 feet of cable tray were relocated for placement of unit 3 ESP control room room. For L/LS FGD, 300 feet of sorbent sluice line was rerouted for unit 3 absorbers.
• Ash removal/conveyance modification	The wet sluice ESP ash discharge system for unit 3 was changed to a dry system for LSD FGD (unit 3: $7.5/kW).
• Stack relining	Reline to prevent corrosion for all L/LS FGD systems ($40/ft^2).
• Rail spur relocation[b]	Approximately 0.2 mile of existing rail spurs in unit 3 absorber/spray dryer area was relocated west of the absorbers. For LSD FGD an additional 0.1 mile was needed for sorbent receiving.

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

[b] Although this adder is specific to Unit 3, it is assumed this scope adder or a similar type adder of equal cost was necessary for Unit 1 and 2 retrofits. This is assumed because a site-specific plot plan prior to the retrofit was not available.

units 1 and 2. Therefore, it was assumed demolition/relocation costs for units 1 and 2 would be equal to the costs incurred for unit 3. Costs for demolition and relocation, as well as stack relining, are based on EPRI guidelines.

The costs of converting the ESP ash removal and conveyance system for unit 3 from a wet to a dry system were included for the LSD FGD system only. Converting the existing fly ash sluice system over to a dry system would be necessary for LSD FGD because spray dryer waste collected in the ESPs could plug the existing sluice lines.

Finally, the absorbers for unit 3 were located in an area near existing railroad spurs. Relocation costs for these spurs has been included as a scope adder for L/LS FGD and LSD FGD systems applied to unit 3. Also, some new rails may be needed for lime sorbent receiving operations on unit 3 LSD FGD systems. These rail costs were also added to the unit 3 LSD FGD control costs. Rail costs are based on estimates provided by ConRail ($\$1 \times 10^6$/mile).

11.2.1.4 Location and Retrofit Factors--

Tables 11-4 thru 11-6 present the location and retrofit factors used for L/LS and LSD FGD. The aggregate location factor presented in the column titled LOCF incorporates the following factors: seismic zone factor of 2, climate zone factor of 0.99, and labor productivity and materials factor of 1.06 (Kentucky). The soil factors selected assume that shallow groundwater exists and that the soil has poor load bearing capacity (e.g., less than 2,000 lb/ft^2).

Additionally, tie-in ductwork length can have a significant impact on the retrofit factor if long tie-in ductwork distances are necessary. As stated previously, the systems were laid out to minimize duct length so low to moderate tie-in distances generally occur for L/LS FGD. However, long duct runs were required for LSD FGD when applied to unit 3. Table 11-7 summarizes ductwork tie-in distances used to develop retrofit factors. Since the distance from waste processing to the absorbers is also a key cost consideration for L/LS FGD, the estimated distances are shown for each FGD cases evaluated.

TABLE 11-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR PARADISE PLANT

		RETROFIT FACTORS											
	All Units	Boiler #1				Boiler #2				Boiler #3			
Items	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT													
Reagent Feed	1.09	1.01	1.02	1.17	1.20	1.01	1.02	1.17	1.20	1.13	1.02	1.13	1.30
SO_2 Removal	1.06	1.06	1.10	1.00	1.17	1.06	1.10	1.00	1.17	1.06	1.10	1.00	1.17
Flue Gas Handling	1.10	1.03	1.30	1.24	1.66	1.03	1.30	1.24	1.66	1.03	1.10	1.31	1.48
Waste Handling	1.08	1.03	1.15	1.03	1.22	1.03	1.15	1.05	1.25	1.03	1.25	1.07	1.38
General Support Equipment	1.09	1.06	1.24	1.00	1.31	1.06	1.24	1.00	1.31	1.06	1.24	1.00	1.31
SCOPE ADJUSTMENTS													
Wet to Dry Ash System	N/A[f]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Chimney	1.08	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.06	1.00	1.06
Demolition	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Rail Repair	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES													
Engineering - %			11					11				11	
General Facilities - %			10					10				10	

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 11-7 for distance assumptions.
[e] AGGF = Aggregate Factor.
[f] N/A = Not applicable.

TABLE 11-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR PARADISE PLANT

Item	All Units	RETROFIT FACTORS Boiler #3			
	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.16	1.06	1.05	1.13	1.26
SO_2 Removal	1.09	1.06	1.10	1.00	1.17
Flue Gas Handling	1.15	1.06	1.50	1.89	3.01
General Support Equipment	1.15	1.06	1.24	1.00	1.00
SCOPE ADJUSTMENTS					
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00
Rail Repair	1.00	1.00	1.00	1.00	1.00
ESP Plate Area Addition	1.06	1.06	1.26	1.00	1.34
Demolition	1.06	1.00	1.00	1.00	1.00
Draft Controls	1.06	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES					
Engineering - %			12		
General Facilities - %			10		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 11-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 11-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES EVALUATED FOR PARADISE PLANT

	RETROFIT FACTORS				
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
Reagent Feed	1.09	1.13	1.02	1.13	1.30
SO_2 Removal	1.06	1.06	1.10	1.00	1.17
Flue Gas Handling	1.10	1.03	1.10	1.31	1.48
Waste Handling	1.08	1.03	1.25	1.07	1.38
General Support Equipment	1.09	1.06	1.24	1.00	1.31

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 11-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 11-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR PARADISE PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
INDIVIDUALIZED CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	195	195	2,500	550
Boiler 2	195	195	2,500	875
Boiler 3	325	130	2,000	1,150
LSD FGD (reuse ESP)				
Boiler 3	520	520	2,000	N/A[c]
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boiler 3	325	130	2,000	1,150

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

For L/LS FGD, the aggregate retrofit factors for units 1 and 2 are similar because most equipment is co-located and as such, is under similar access/congestion and underground obstruction conditions. For example, absorbers, waste processing, sorbent receiving and preparation systems for both units are located together as shown in figure 11-3.

In general, most aggregate retrofit factors for units 1, 2, and 3 are low to medium because most process areas are built in locations with relatively free access and little congestion compared to a new plant installation. One exception to this is the flue gas handling system for units 1 and 2. Compared to unit 3, the ductwork for units 1 and 2 was complex and located in a very tight arrangement with close proximity to the stack. Because of this, medium access/congestion factors were used for the flue gas handling areas. Also, a medium access/congestion factor was used for the unit 3 waste processing area because of the overhead electrical transmission lines near this equipment.

Underground obstruction factors for all three units were medium to high because most equipment was located close to the powerhouse and because some significant obstructions were encountered by various L/LS FGD process areas. For example, ash sluice line trenches were located near the absorbers for all 3 units and near the sorbent preparation system for unit 3.

In general, the aggregate retrofit factors for most process areas within unit 3 were low because the process equipment was located in areas with little congestion and relatively free access. The only exceptions are flue gas handling and ESP upgrading. The ductwork tie-in point for LSD FGD was prior to the ESP so the tie-in ductwork arrangement was complex and there was little access and extreme congestion. Also there were relatively long tie-in duct runs associated with installing the ductwork. Because the existing stack severely restricts the left side duct runs into and out of the spray dryer stacked ducts, a high access congestion factor was used for the flue gas handling area. Also, high underground obstruction factors were assigned to the flue gas handling area because of its proximity to the ash sluice pipeline trench. Thus, the aggregate retrofit factor for the flue gas area was high. As was the case with L/LS FGD, high underground obstruction factors were used for the SO_2 removal process area.

11.2.1.5 Overall Retrofit Factors and Costs--

Table 11-8 presents the overall retrofit factors and costs for all FGD cases. The range of costs shown for L/LS FGD on unit 3 represent the different L/LS process options evaluated: forced oxidation limestone and limestone enhanced with adipic acid, and lime and lime enhanced with MgO. For units 1 and 2, cost represents the forced oxidation limestone technology. Figures 11-5 and 11-6 summarize the plant level costs of installing L/LS and LSD FGD at unit 3, respectively. The data point labeled low cost shows the impact of scrubber optimization and use of adipic acid additives.

The application of L/LS FGD at unit 3 would reduce plant level SO_2 emissions by approximately 63,300 tons per year assuming a 90 percent level of control. Application of LSD FGD at unit 3 would reduce plant level SO_2 emissions by approximately 53,700 tons per year with ESP reuse.

11.2.2 Coal Switching/Blending

Table 11-9 presents the coal analyses used at Paradise in 1985 and the alternative coal used to evaluate the impact of coal switching. The switch coal is low sulfur Kentucky coal having a sulfur content of 1.0 percent. Figure 11-7 presents the plant level cost and emission reduction for switching to a low sulfur coal at unit 3. Curves were generated to show the impact of different coal fuel price differentials. The lower curve represents a 1985 fuel price differential of $14.17 per ton between the existing cleaned coal and an eastern Kentucky low-sulfur coal. The lower curve shows the impact of an additional fuel price differential of $15 per ton over the 1985 fuel price differentials.

Approximately 46,300 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.5 pound per million Btu SO_2 emission rate. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 11-10.

No additional costs for particulate control upgrade were required after SO_3 conditioning. No costs are included for coal segregation facilities. These facilities may be necessary because units 1 and 2 would likely

TABLE 11-8. L/LS AND LSD FGD COSTS FOR PARADISE PLANT
(August 1987 Dollars)

		IAPCS Retrofit Costs[a]		
Case Description	Overall Retrofit Factor	Capital Cost (\$/kW)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.35	175.1	1,064	20.0
Boiler 2	1.35	174.4	1,058	19.9
Boiler 3	1.32	155.4-182.6	956-1,109	18.0-20.9
LSD FGD (reuse ESP[b])				
Boiler 3	1.71	151.2	947	15.1
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boiler 3	1.32	118.3	723	13.6

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] No plate area increase needed.

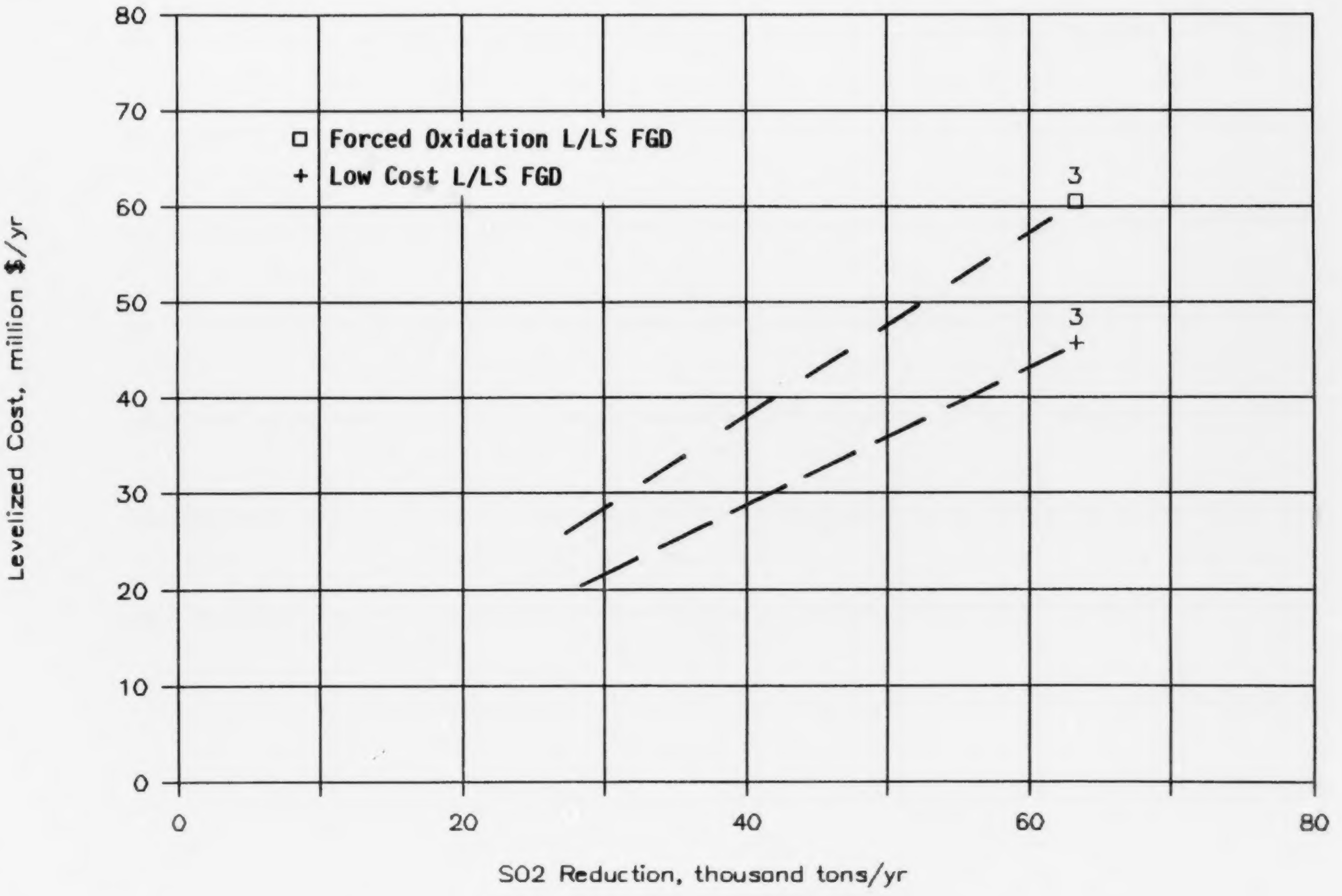

Figure 11-5. Paradise Plant L/LS cost versus SO_2 reduction.

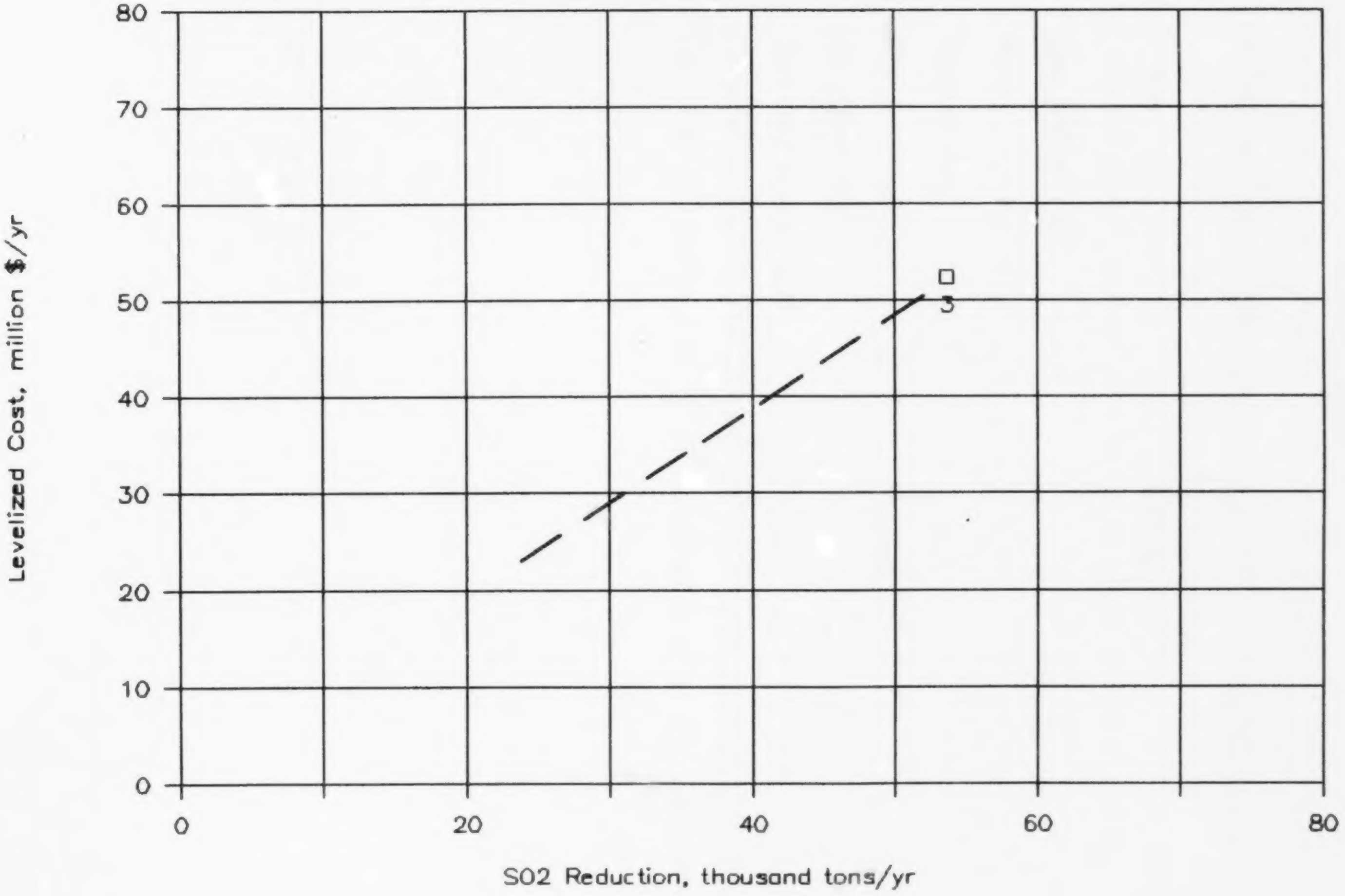

Figure 11-6. Paradise Plant lime spray dryer FGD cost versus SO_2 reduction.

TABLE 11-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR PARADISE PLANT

Item	Existing Coal	Switch Coal
	Boiler 3	Boiler 3
COAL PARAMETERS		
Percent Sulfur	2.7	1
Percent Ash	6.8	10.5
Btu Per Pound	11,800	12,100
ESP PARAMETERS		
Existing/Needed SCA[a]	345	276

[a] Specific collection area in $ft^2/1,000$ acfm after SO_3 conditioning.

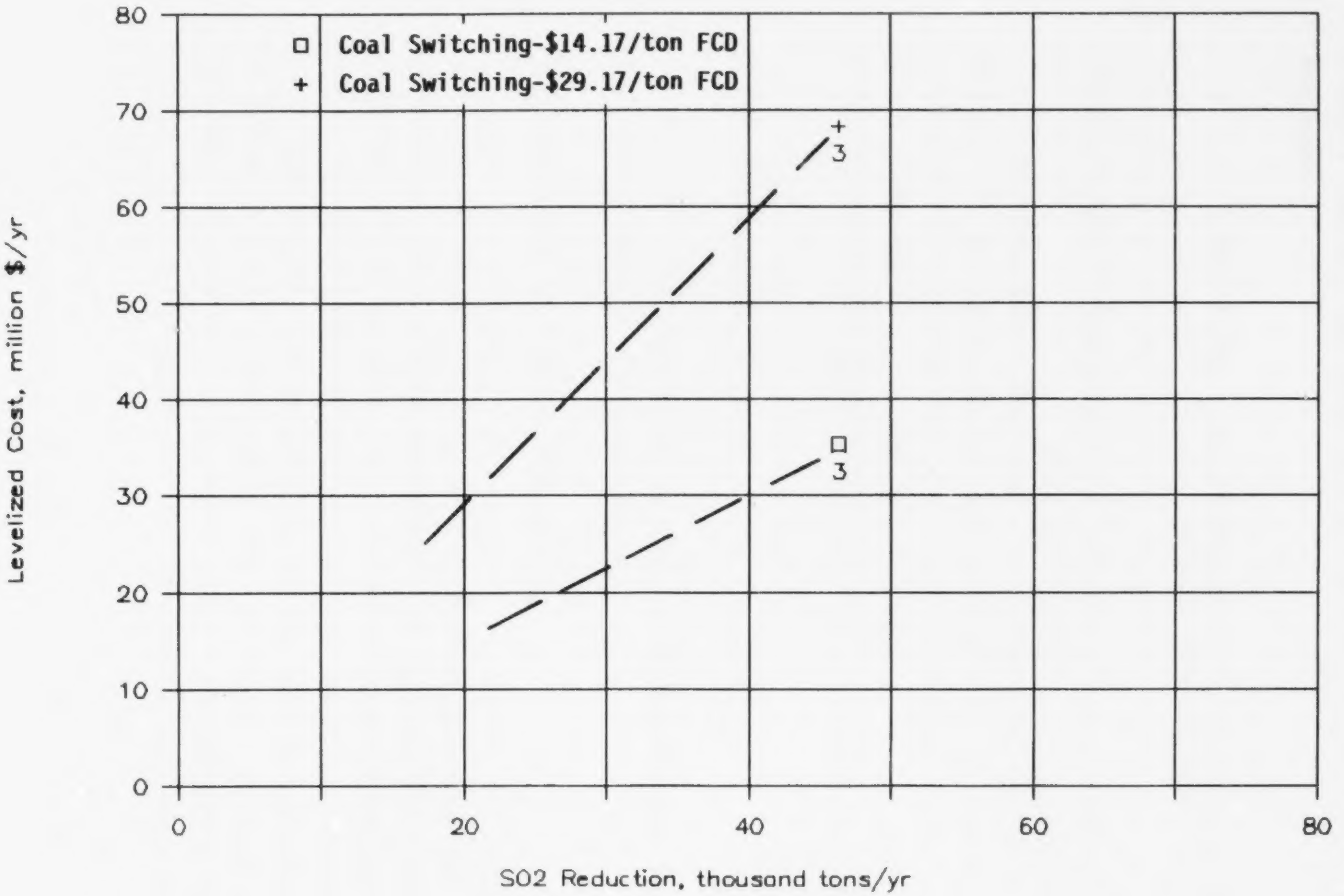

Figure 11-7. Paradise Plant coal switching costs versus SO_2 reduction.

continue to operate using the cleaned coal. Additionally, because coal ash analysis were not available, boiler impacts due to switching coal were not evaluated.

TABLE 11-10. COAL SWITCHING COSTS FOR PARADISE PLANT
(August 1987 Dollars)

		@ $14.17/ton FCD		@ $29.14/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost (\$/ton SO_2)	Levelized Cost (mills/kWh)
3	46,300	752	10.4	1,462	20.2

11.2.3 Physical Coal Cleaning

Physical coal cleaning was not evaluated for Paradise because the coal is currently being extensively cleaned.

11.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data. The following control technologies were considered: furnace sorbent injection (FSI) and duct spray drying (DSD). The following discussion presents the retrofit issues and cost/performance estimates developed.

11.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit application. The overall retrofit factors developed for these technologies focus on developing scope adders which are not included in the base capital cost assumptions. These include conversion of ESP wet fly ash handling systems to dry handling/storage, new rail spurs for sorbent receiving, and additional ESP plate area. Basic assumptions and cost adjustments made for FSI and DSD at Paradise unit 3 are presented in table 11-11. These technologies are not applicable to units 1 or 2, since both have existing FGD systems. A brief discussion follows describing how the retrofit factors were derived for each technology.

11.3.1.1 Furnace Sorbent Injection--

Furnace sorbent injection was evaluated for unit 3 only. The FSI equipment layout is similar to the DSD layout except that furnace injectors rather than duct injectors would be used. Also, day bins would be located close to each unit, and a sorbent preparation area is not necessary.

11.3.1.2 Duct Spray Drying--

Duct spray drying using a lime slurry sorbent was evaluated for retrofit to boiler 3. As is the case for LSD FGD, it was estimated that the existing particulate control system can be used with no additional plate area. Since the existing ESP is adequate, the new baghouse case was not considered as an option.

A lime slurry would be injected into the duct as it passes out of the air heater. This injection point would allow adequate time for SO_2 absorption to occur prior to particulate collection. About 130 feet of straight duct and old ESP box area are available for the sorbent to dry before collection, thus allowing the slurry to completely dry prior to entering the retrofit ESPs. The lime receiving/storage and preparation systems are the same as used for LSD FGD.

TABLE 11-11. SCOPE ADJUSTMENTS FOR FSI AND DSD AT PARADISE PLANT

Item	Boiler 3
BASIC ASSUMPTIONS	
Approximate access/congestion rank	Low
Can the existing ESP be upgraded?	Yes
Was a new baghouse evaluated?	No
Distance to final waste disposal (miles)	1
SCOPE ADDERS	
Install dry ash handling system	8,510[a]
New Rails	300
Additional duct work (ft)[b]	N/A[c]
Duct demo length (ft)[b]	N/A
Building demo area (ft^2)[b]	N/A
ADDER COSTS AND RETROFIT FACTOR SUMMARY	
Scope adder costs for new baghouse (10^3 \$)[a]	N/A
Scope adder costs for ESP reuse (10^3 \$)[a]	8,810
Baghouse retrofit difficulty factor	N/A
ESP upgrade retrofit difficulty factor (for plate area addition)	1.34

[a] June 1985 dollars.

[b] Not applicable when the existing ESP is used.

[c] N/A = Not applicable.

11.3.1.3 Overall Retrofit Factors and Costs--

Table 11-12 summarizes the costs estimated for the sorbent injection technologies. Figure 11-8 presents the cost of retrofitting FSI and DSD on boiler 3. For duct spray drying, plant-wide SO_2 emissions would be reduced by 33,800 tons per year. For the FSI technology, SO_2 emissions would be reduced by 35,200 and 49,300 tons per year, assuming 50 and 70 percent SO_2 removal, respectively.

11.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

Unit 3 is a large unit (1,150 MW) and has been in service only 17 years, which makes it a very unlikely candidate for FBC/CG retrofit.

11.4 NO_x CONTROL TECHNOLOGIES

This section presents the cost and performance estimates developed for NO_x controls at the Paradise plant. Control applicability and performance are discussed in the following sections for each boiler. The controls considered are as follows: natural gas reburn and selective catalytic reduction. The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls at the Paradise Plant boilers are discussed in the following sections.

11.4.1 Low NO_x Burners

The use of low NO_x burners and overfire air controls is not applicable to any of the boilers at Paradise because they are all cyclone-fired units. However, the use of natural gas reburning is evaluated for all three.

11.4.2 Natural Gas Reburning

Natural gas reburning is assumed to be applicable to all three boiler units. A NO_x emission reduction of 50 percent is estimated to be achievable with injection of 15 percent of the boiler heat input as natural gas.

TABLE 11-12. RETROFIT COSTS FOR FSI AND DSD FOR PARADISE PLANT (August 1987 Dollars)

Case Description	IAPCS Captial Cost (\$/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost (\$/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50 % removal)[a] Boiler 3	49.8	8.8	842	35,200
Furnace Injection (70 % removal)[b] Boiler 3	50.9	9.0	613	49,300
Duct Spray Drying (reuse ESP) Boiler 3	43.8	6.3	623	33,800

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

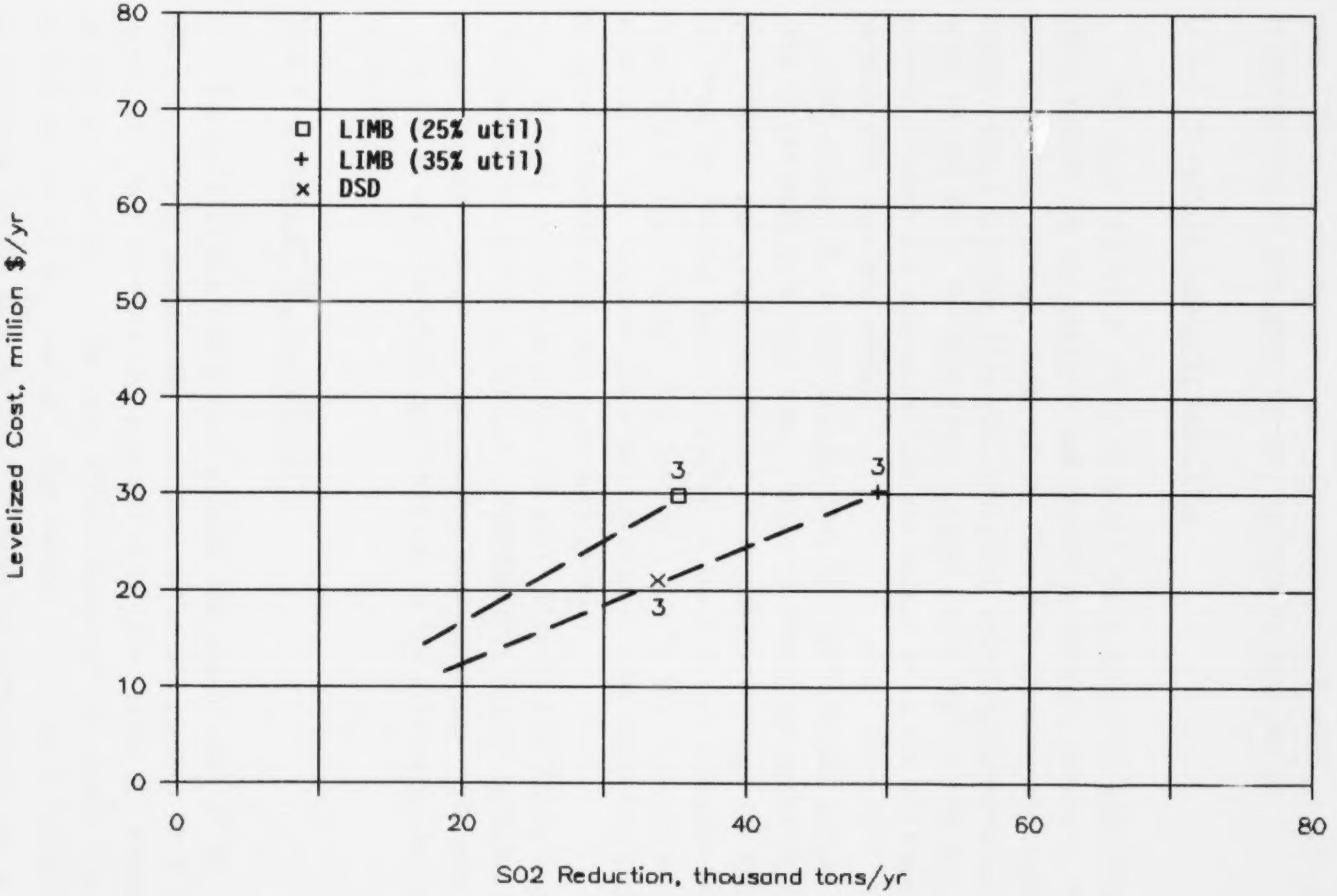

Figure 11-8. Paradise Plant FSI/DSD cost versus SO_2 reduction.

Application of NGR at Paradise would require installation of a gas pipeline to the plant (assumed to be five miles), gas distribution lines and controllers to the boilers, and gas injection and overfire air port installations in the upper furnace section of each boiler.

11.4.3 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700°F for coal-fired systems would require the SCR system to be located between the economizer and air heater or at the tail end before the chimney with flue gas reheat.

For units 1-3, it was assumed that the tail-end SCR system would be used to minimize unit down time. Boiler 3 flue gases would be diverted to the reheater and catalytic reactor after passing through the ESPs. Hot flue gas from the reactor would be cooled in the flue gas reheater before returning to the chimney. For boilers 1 and 2, the flue gas would be diverted to the reheater after the scrubbers. The catalytic reactors would be located behind each unit near each chimney.

Table 11-13 summarizes the SCR unit retrofit difficulty and scope adjustments for boiler units 1-3. The retrofit factor includes access and congestion and underground obstruction considerations. The area behind units 1-3 is not congested, and moderate to low difficulty factors were assigned.

11.4.4 Summary of NO_x Control Costs

Table 11-14 and figure 11-9 present the annual cost of NO_x controls. NGR assumes a 50 percent NO_x reduction, while SCR assumes an 80 percent reduction. NGR retrofit would result in a plant level NO_x reduction of 29,300 tons per year. The cost effectiveness of NGR ranges from $1,182 to $1,200 per ton of NO_x removed. Application of SCR would reduce NO_x emissions by 47,100 tons per year if 80 percent reduction can be achieved; the cost per ton of NO_x removed ranges from $3,304 to $3,694 per ton of NO_x removed.

TABLE 11-13. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR PARADISE PLANT
(August 1987 Dollars)

Item	Boiler 1	Boiler 2	Boiler 3
Site access and congestion for SCR reactor	Low	Low	Low
SCOPE ADDER PARAMETERS			
Building demolition (1,000$)	0	0	0
Ductwork demolition (1,000$)	117	117	169
New duct length (feet)	475	850	450
New duct costs (1,000$)	7,372	13,191	9,306
New heat exchanger (1,000$)	6,011	6,011	8,069
Total scope adder costs (1000$)	13,500	19,319	17,544
Retrofit factor for SCR	1.16	1.16	1.16
General facilities (percent)	20	20	17

TABLE 11-14. NO_X CONTROLS COSTS FOR PARADISE PLANT
(August 1987 Dollars)

NO_x Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X Reduced (tons/year)
Natural Gas Reburn	1	50	12.6	1,200	4.7	8,000
	2	50	12.6	1,200	4.7	8,000
	3	50	11.5	1,182	4.7	13,300
Selective Catalytic Reduction	1	80	123.0	3,612	22.9	12,900
	2	80	131.8	3,694	23.4	12,900
	3	80	111.7	3,304	20.9	21,300

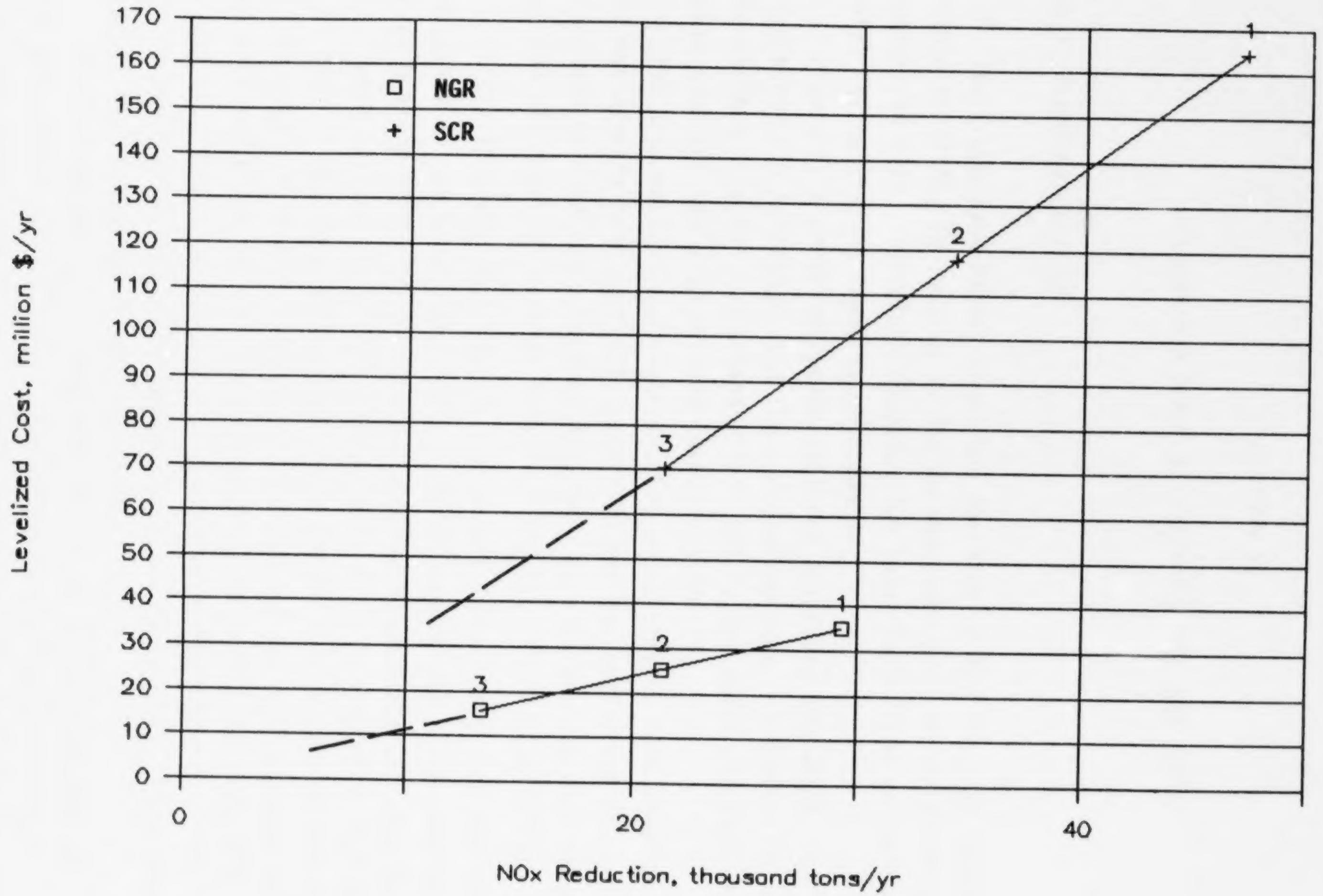

Figure 11-9. Paradise Plant NO_x controls cost versus NO_x reduction.

SECTION 12

CUMBERLAND PLANT RETROFIT FACTORS AND COSTS

12.1 PLANT DESCRIPTION

The Cumberland Plant, owned and operated by the Tenessee Valley Authority (TVA), is located in the northwestern part of Tennessee near Cumberland City. The plant contains two large coal-fired boilers and has a total net generating capacity of 2,538 MW.

Figure 12-1 shows the power station, auxiliary equipment, key support structures and buildings, and the surrounding area. The plant is bounded to the northeast by the Cumberland River, and to the south and east are open areas used for ash disposal and settling ponds.

The area east of the electrostatic precipitators ESPs labeled "B" and "C" has already been partially excavated and has sufficient space for placement of some FGD system components. This area would also be suitable for the placement of sorbent injection and SCR system components.

Table 12-1 presents the key design and operational data for the existing equipment at the Cumberland Plant. Units 1 and 2 are pulverized coal-fired boilers each with a nameplate generating capacity of 1,300 MW. Units 1 and 2 were started up in 1973, and both burn a 2.9 percent sulfur coal.

Coal is received at the plant from barges and is sent by conveyor either to the coal pile area or to one of three 15,000 ton coal storage silos. From the pile and silos the coal is conveyed to the pulverizer feed bins. A 60-day coal supply is maintained. Approximately 80 percent of the coal burned has been washed using medium flotation techniques. This process reduces coal sulfur by about 35 percent.

Particulate emissions from both units are controlled with retrofit ESPs with SCAs of 375 $ft^2/10^3$ acfm. The original ESP system containing three boxes per unit was replaced in 1982 with the addition of six new ESP boxes

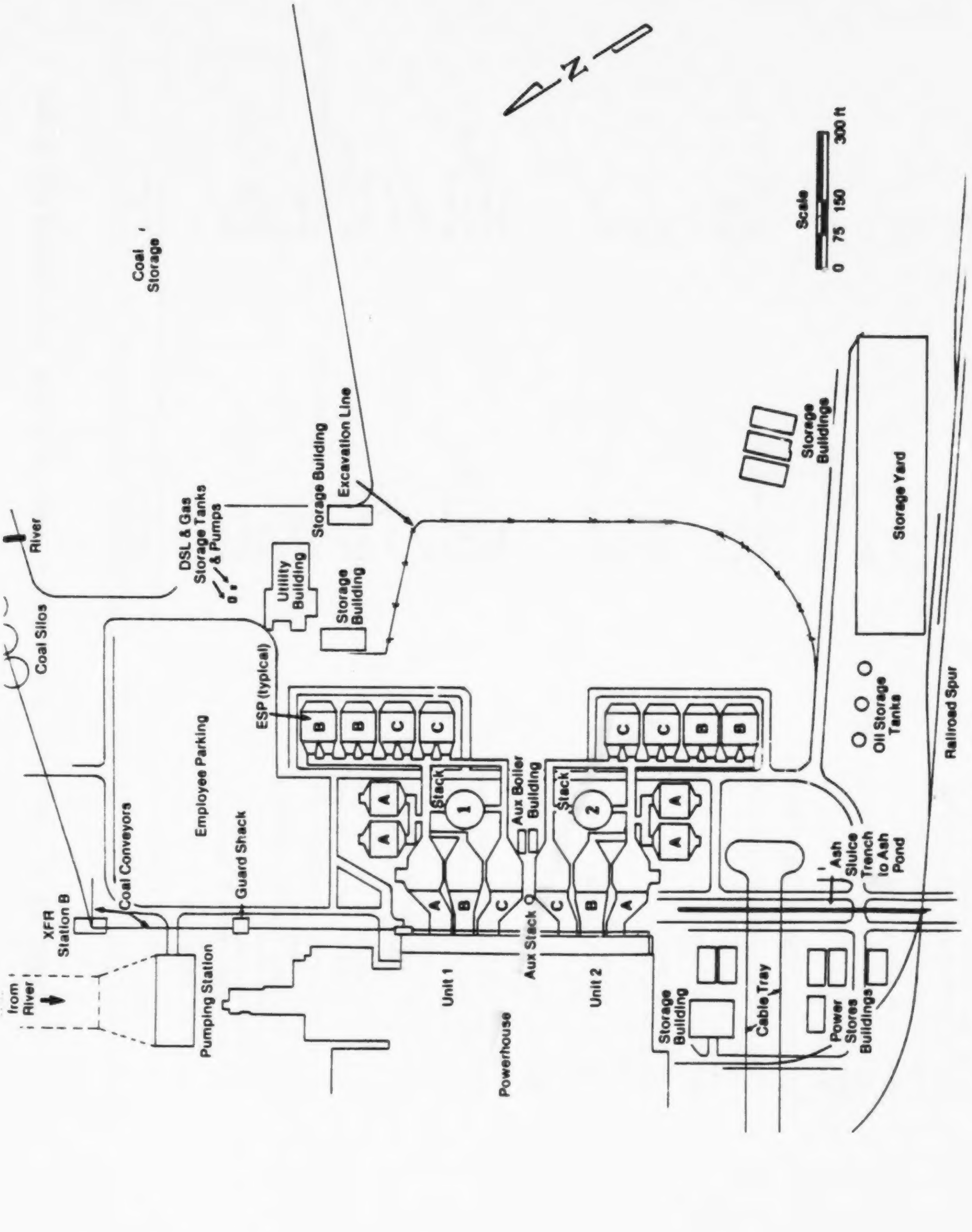

Figure 12-1. Cumberland Plant plot plan.

TABLE 12-1. KEY DESIGN AND OPERATIONAL DATA FOR THE CUMBERLAND PLANT

Item	Boiler 1	Boiler 2
BOILER AND STACK DATA		
Net generating capacity (MW)	1269	1269
Boiler manufacturer	Babcock & Wilcox	Babcock & Wilcox
Installation date	1973	1973
Capacity factor (10 year projected)	60	60
Heat rate (Btu/kW-hr)	9,950	9,950
Boiler type/firing type/bottom type	P.C./wall (opposed)/dry	P.C./wall (opposed)/dry
Boiler dimensions, (ft, D x W x H[a])	69 x 78 x 110	69 x 78 110
Burner type/number of burners (# EL x #/EL)	Circular	Circular
Burner spacing (vert x horiz, ft)	(4x--[b]) x 2	(4x--[b]) x 2
Burner zone heat release rate (Btu/hr-ft^2)	1,135	1,135
Excess air (percent)	20	20
Draft type	Balanced	Balanced
Flue gas flow rate (1000 acfm @ °F)	4,500 @ 291°F	4,500 @ 291°F
Stack size (height x diameter, feet)	1,000 x 31	1,000 x 31
Stack liner type	Steel	Steel
FUEL AND SORBENT DATA		
Coal quality[c]		
Heat content (Btu/lb)	11,643	11,650
Volatile matter (percent)	28	28
Ash (percent)	9.2	9.1
Moisture (percent)	10.8	10.8
Sulfur (percent)	2.9	2.9
Coal delivery methods		
Current	Barge	Barge
Design	Barge	Barge
Likely method for sorbent delivery	Pond (on-site)	Pond (on-site)
PARTICULATE CONTROL EQUIPMENT DATA		
Type of control	ESP/cold side	ESP/cold side
New/retrofit installation		
ESP specific collection area (ft^2/10^3 acfm)	374.4	374.4
Total plate area (10^3 ft^2)	1797	1797
Emission standards (lb/10^6 Btu)	0.1	0.1
ESP outlet emissions (lb/10^6 Btu)[d]	0.01	0.01
Design coal sulfur (percent)	1.75	1.75
Gas conditioning	None	None
Tested efficiency/design efficiency	99.7/99.9	99.6/99.9

(Continued)

TABLE 12-1. (CONTINUED)

Item	Boiler 1	Boiler 2
NITROGEN OXIDE CONTROL EQUIPMENT DATA		
NO_x control equipment	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA		
SO_2 control equipment	None	None
SOLID WASTE DISPOSAL DATA		
Ash transport system type		
Boiler bottom ash	Wet sluice	Wet sluice
Economizer bottom ash	Wet sluice	Wet sluice
Fly ash	Wet sluice	Wet sluice
Ash disposal method	Pond	Pond
Existing Pond Capacity	8 Years	8 Years

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual rate.

per unit. The older ESPs normally are not used but could be put into service.

The retrofit ESPs easily meet the applicable particulate emission standard of 0.1 lb/10^6 Btu. Plant personnel felt that the coal sulfur content could be dropped from its current level of 2.9 percent to 1.5 percent (a 48 percent reduction) without exceeding the existing particulate standard.

Ash from the boilers and ESPs for both units is sluiced to the ash pond located south and southeast of the powerhouse. The existing pond is almost filled to capacity, and the plant is evaluating alternative disposal strategies. It is likely that a new pond will be built on-site at the southern corner boundary. An abandoned rock quarry also exists in that location which could be used for FGD waste disposal.

12.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Cumberland plant include lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching and physical coal cleaning. Limestone with FGD with forced oxidation was also evaluated. The following discussion presents the retrofit issues and cost/performance estimates developed for each technology.

12.2.1 Lime/Limestone and Lime Spray Drying FGD

12.2.1.1 Control Cases Evaluated--

Table 12-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. For the L/LS FGD technology, the only cases evaluated were using limestone as the sorbent, since this technology would likely be utilized with a limestone quarry nearby. For the conventional limestone FGD case, the FGD waste was assumed to be stabilized with dry fly ash from the ESPs. Two L/LS FGD control configurations were considered at Cumberland: (1) separate control systems

TABLE 12-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR CUMBERLAND PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Removed (tons/year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	2.9	141,000
Boiler 2	90	2.9	141,000
LSD ESP (reuse ESP)			
Boiler 1	70	2.9	110,000
Boiler 2	70	2.9	110,000
LOW COST CONTROLS			
L/LS FGD			
Boiler 1	90	2.9	141,000
Boiler 2	90	2.9	141,000

for each unit, and (2) a separate low capital cost system for each unit. On-site waste disposal was assumed for all FGD cases.

For LSD FGD systems two separate process options were initially considered: (1) where the existing ESPs are used to collect the increased loading due to spray drying, and (2) where the existing ESPs cannot handle the increased loading, and a new baghouse is required. Because the existing ESPs have a significant amount of excess capacity, LSD with reuse ESP was the only case considered for which costs are presented.

In some cases more than one boiler at a plant can share FGD control system components such as stacks, sorbent receiving and preparation systems, and waste storage facilities. This sharing of control system components can act to reduce costs of the overall control system due to the economy of scale associated with components shared. However, shared systems were not evaluated for the Cumberland Station because the control equipment already is very large, and any economy of scale associated with sharing would be marginal.

SO_2 removal efficiency for L/LS FGD is assumed to be 90 percent. Removal efficiency for LSD FGD is assumed to be 70 percent when the existing ESP is reused.

12.2.1.2 Layout of Equipment and Design Basis--

The placement of the major components of the SO_2 control system is an important consideration in the development of retrofit factors and costs. Site-specific access/congestion and other factors can complicate the placement of control equipment, impacting retrofit cost. For each L/LS FGD and LSD FGD case considered, a simplified plant drawing or conceptual design was prepared illustrating the placement of the key components. Absorbers, spray dryers, ductwork, clarifiers/vacuum filters, sorbent receiving/storage, sorbent preparation, and waste storage systems are shown. All systems were sized based on the nameplate capacity for each unit. When sizing sorbent receiving and storage equipment, it was assumed that limestone would be the sorbent of choice for the L/LS FGD technology and lime for LSD FGD.

The following is a list of the drawings developed to illustrate the SO_2 control cases listed.

Figure Number	FGD Control Case Description
12-2	Conventional limestone FGD for units 1 and 2
12-3	Lime spray drying FGD for units 1 and 2 with reuse of existing ESPs

These drawings are not intended to represent the accuracy and detail associated with an engineering drawing but are approximately to scale. They were prepared from drawings supplied by the plant, sketches and measurements made during the plant visit, and photographs taken during the plant visit.

The L/LS FGD absorbers were located in the excavated area directly southeast of the new ESPs. For both units, limestone storage and preparation facilities were located on the open high ground directly southeast of the excavated area. The on-site solid waste disposal area was located in the southern-most corner of the plant about 0.9 miles from the powerhouse. TVA indicated this site would likely be used for FGD waste disposal if FGD equipment were added at the plant.

For the LSD FGD cases, the absorbers were located as close to the ESP inlet ductwork as possible. For unit 2 this required the absorber sections to be separated so as not to interfere with the electrical cable tray located south of unit 2. Plant personnel indicated they would not relocate this cable tray because it is critical to plant operations. Thus, the split flow design selected for unit 2: (1) minimizes interference with the cable tray, (2) minimizes duct run length, and (3) maximizes the spray dryer inlet temperature.

12.2.1.3 Scope Adjustments

In order to retrofit control systems at the Cumberland Station, some existing equipment must be modified and costs not included in the IAPCS cost models must be added to account for this equipment. These are referred to as scope adjustments or cost adders and are summarized in table 12-3 for all FGD cases evaluated.

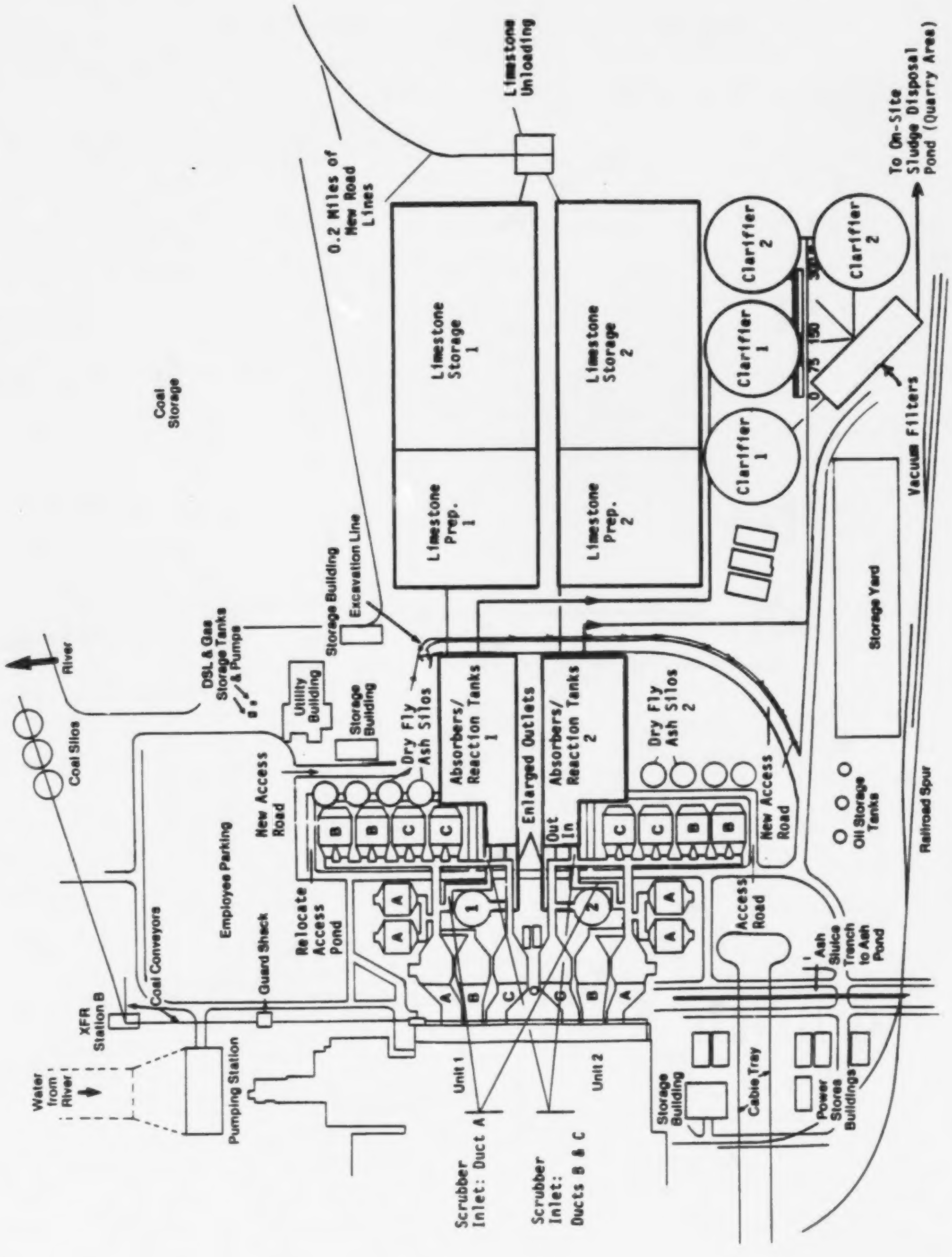

Figure 12-2. Cumberland Plant conventional limestone FGD for units 1 and 2.

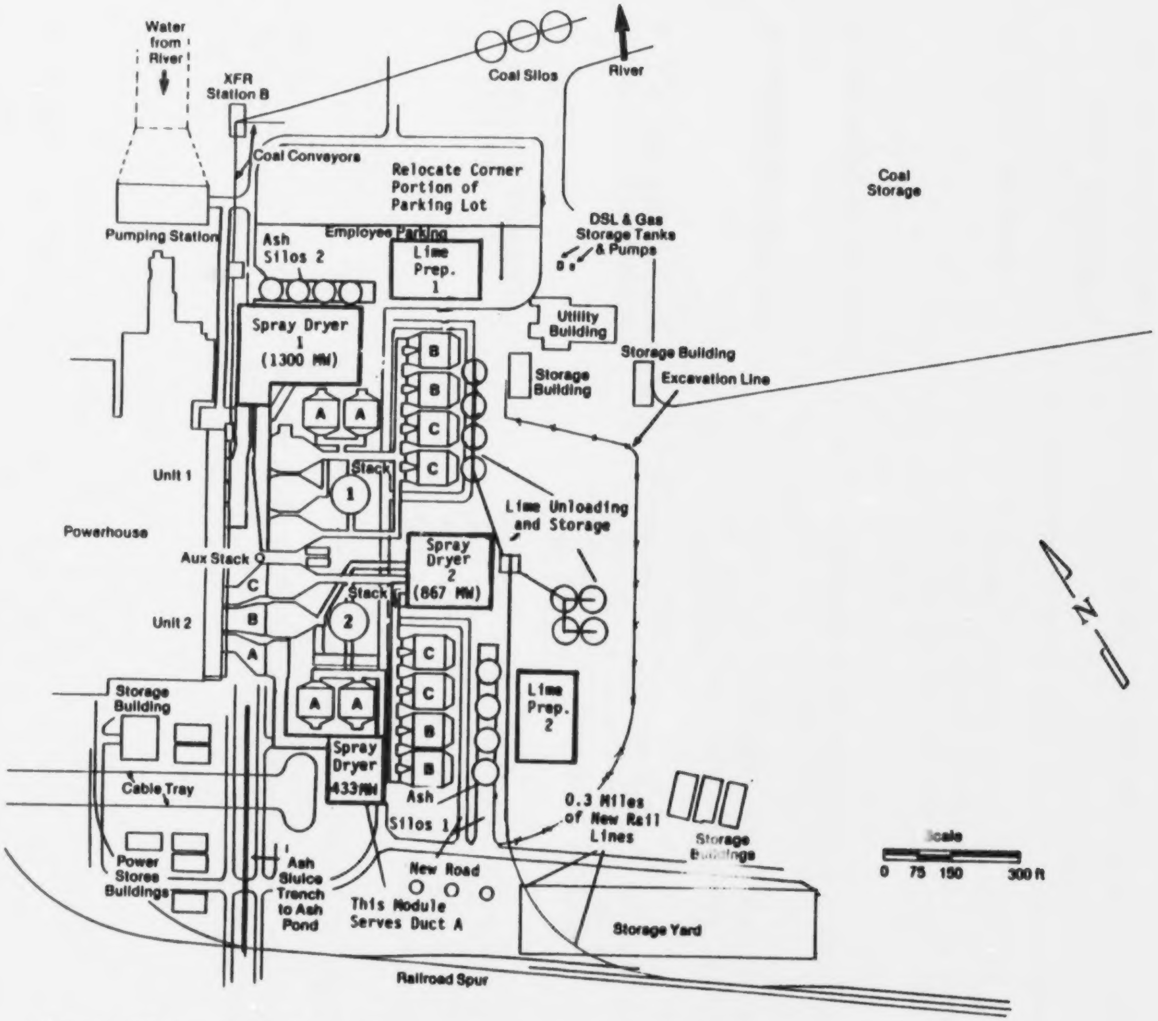

Figure 12-3 Cumberland Plant limes spray drying FGD for units 1 and 2.

TABLE 12-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR CUMBERLAND PLANT

Scope Adjustment	Description[a]
• Stack relining	It was assumed necessary to reline the existing steel lined stacks to prevent corrosion for all conventional FGD systems (\$40/ft^2).
• Balanced draft controls	Balanced draft controlswere required with all SO_2 controls (\$1.20/kW).
• Ductwork demolition	Duct demo costswere added for all systems as necessary. Cost dependent upon amount demolished.
• Fly ash removal/conveyance system modification	Units 1 and 2 ESP systems changed from wet sluice to dry for LSD FGD and conventional limestone systems (\$7.28/kW).
• New rail spur/repair existing rails	New rails and existing rail upgrading were necessary to accommodate sorbent shipments for all cases evaluated (new rails: \$1,000,000/mile; existing rail repair: \$250,000/mile).

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

The cost of converting the ESP ash removal and conveyance systems for units 1 and 2 from a wet to a dry system was included for conventional limestone and LSD FGD systems. Dry fly ash is necessary to stabilize the sludge from the conventional limestone process and thus to improve its handling properties. Converting the existing fly ash sluice system over to a dry system was also necessary for LSD FGD systems because spray dryer waste collected in the ESPs could plug the existing sluice lines.

In the FGD system designs it was assumed that a portion of the in-plant rail lines could be used for receiving lime and/or limestone shipments. However, plant personnel indicated some in-plant rail lines were in need of repair so the cost of repairing or upgrading the portion of those rail lines was included. Also, all cases require that a new railroad spur off the existing lines be built in order to access those areas most suitable for sorbent receiving/storage. New rail and rail repair costs used are based on estimates supplied by ConRail.

The costs for modifying the draft controls, duct demolition, and stack relining were based on EPRI guidelines. The cost to relocate the employee parking area and plant roads around the ESP/stack area was accounted for in the general facilities cost.

12.2.1.4 Location and Retrofit Factors--

Location factors adjust the cost of a control system from the EPRI base case location to any other location. These factors account for the site-specific effects of seismic zone, climate, material cost, labor productivity, and soil conditions. Retrofit factors are site-specific constraints that account for the cost associated with the site-specific difficulty of retrofitting control equipment. These factors account for underground obstructions, site accessibility and congestion, distance to the control system (tie-in ductwork), and distance to the sorbent preparation and waste processing equipment. Tables 12-4 thru 12-6 present the location and retrofit factors used for L/LS FGD and LSD-FGD. Table 12-6 summarizes the retrofit factors for the low capital cost boiler case.

TABLE 12-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES FOR CUMBERLAND PLANT

		RETROFIT FACTORS							
	All Units	Boiler #1				Boiler #2			
Items	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	0.97	1.01	1.05	1.00	1.06	1.01	1.05	1.00	1.06
SO_2 Removal	0.99	1.00	1.30	1.00	1.30	1.00	1.10	1.00	1.10
Flue Gas Handling	1.10	1.01	1.30	1.19	1.56	1.01	1.30	1.19	1.56
Waste Handling (conventional)	1.00	1.03	1.05	1.06	1.15	1.03	1.05	1.10	1.19
General Support Eqp.	0.97	1.01	1.08	1.00	1.09	1.01	1.08	1.00	1.09
SCOPE ADJUSTMENTS									
Chimney Reline	0.97	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Demolition/Relocation	0.95	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	0.95	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			11				11		
General Facilities - %			5				10		

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[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 12-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 12-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR CUMBERLAND PLANT

Items	All Units	RETROFIT FACTORS							
		Boiler #1				Boiler #2			
	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.04	1.06	1.15	1.00	1.22	1.01	1.05	1.00	1.06
SO_2 Removal	0.98	1.03	1.30	1.00	1.34	1.00	1.10	1.00	1.10
Flue Gas Handling	1.03	1.03	1.30	1.54	2.06	1.01	1.10	1.41	1.57
General Support Eqp.	1.03	1.06	1.24	1.00	1.31	1.01	1.08	1.00	1.09
SCOPE ADJUSTMENTS									
ESP Plate Area Addition	1.00	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Demolition/Relocation	0.95	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	0.95	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 12-7 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 12-6. RETROFIT FACTOR SUMMARY FOR LOW COST L/LS FGD CASES FOR CUMERLAND PLANT

Items	All Units LOCF[a]	RETROFIT FACTORS							
		Boiler #1				Boiler #2			
		UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	0.97	1.01	1.05	1.00	1.06	1.01	1.05	1.00	1.06
SO_2 Removal	0.99	1.00	1.30	1.00	1.30	1.00	1.10	1.00	1.10
Flue Gas Handling	1.10	1.01	1.30	1.19	1.56	1.01	1.30	1.19	1.56
Waste Handling (conventional)	1.00	1.03	1.05	1.06	1.15	1.03	1.05	1.10	1.19
General Support Eqp.	0.97	1.01	1.08	1.00	1.09	1.01	1.08	1.00	1.09

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 12-7 for distance assumptions.
[e] AGGF = Aggregate Factor.

The aggregate location factor presented in the column titled LOCF incorporates the following factors: seismic zone factor for zone 2 (1.002-1.009), climate zone factor of 0.99, and labor productivity and materials factor of 0.95 (Tennessee). In general the soil factor selected were for a moderate high cost situation because of the need to excavate the fractured bed rock material. However, for the LS FGD Case, the maximum removal and flue gas handling areas soil factors were used because of the need for extensive excavation.

Table 12-7 presents the duct tie-in distances and distances between process areas used. Since the distances from waste processing and sorbent preparation areas to the absorbers are also a key cost consideration for L/LS FGD, the estimated distances are shown for all L/LS FGD cases evaluated.

For all FGD systems (L/LS FGD and LSD-FGD) aggregate retrofit factors for unit 1 are generally the same or higher than the aggregate factors for unit 2. For example, with all L/LS FGD cases, the SO_2 removal or absorber section factor is 1.30 for unit 1 and 1.10 for unit 2. A higher factor for unit 1 is used because the absorber location for unit 1 is more crowded with existing structures and has reduced access compared to unit 2 (see figure 12-2). The absorber cost is the most significant cost item for all the FGD systems so the higher retrofit factor for unit 1 absorbers is the main reason the overall retrofit factors are higher for unit 1.

Flue gas handling retrofit factors are generally medium to high for all cases. This occurs for several reasons, including: (1) a significant amount of tie-in ductwork is needed to retrofit the FGD systems on units 1 and 2 and (2) the duct "A" and "B" tie-ins are generally difficult for all systems because construction is required in very crowded locations.

Little data was available concerning underground obstructions at the plant so some general assumptions were made concerning selection of underground obstruction factors. For LSD-FGD on unit 1, medium factors were used for some process areas because of their proximity to the pump station and powerhouse which is an area that likely contains underground water lines. For equipment located away from the main powerhouse, and for equipment located in the excavated area in back of the ESPs, low underground factors

TABLE 12-7. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR CUMBERLAND PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Outlet[b]	Sorbent Prep to Absorber (feet)	Distances from Absorber to Waste Treatment (feet)
L/LS FGD				
Boiler 1	160	180	100	970
Boiler 2	160	180	100	1,500
LSD FGD (reuse ESP)				
Boiler 1	322[c]	368	100	N/A[d]
Boiler 2	230	334	100	N/A

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] This is a weighted average distance since two separate spray dryer modules are used and different sizes and lengths of duct feed each module. Individual duct lengths for each module were weighted by the percent of the total flow passing through the duct. Summation of the weighted lengths is assumed to be a reasonable estimate of the appropriate length to use in the EPRI procedures.

[d] N/A = Not applicable for spray drying FGD.

were used. Based on the other plants visited, small numbers of underground obstructions are usually encountered away from the powerhouse area. Also, obstructions are not expected to occur in the excavated area because the surface is rock and it is doubtful pipes or other interferences are buried there.

12.2.1.5 Overall Retrofit Factors and Costs--

Table 12-8 presents the overall retrofit factors and costs for all FGD cases. The range of costs shown for L/LS FGD represent the different L/LS FGD process options examined: limestone conventional forced oxidation and organic acid enhanced, and lime slurry conventional and MgO enhanced. Figures 12-4 and 12-5 summarize the plant level costs of installing L/LS and LSD FGD. Only costs for conventional lime FGD were plotted on Figure 12-4.

Application of L/LS FGD at Cumberland would reduce SO_2 emissions by 282,000 tons per year. The low capital cost control case reduces annual cost of control by 16 percent. This is result of scrubber module optimization by using organic acid additives, eliminating spare absorbers and maximizing absorber size.

Application of the LSD FGD technology at Cumberland would reduce SO_2 emissions by 220,000 tons per year. This is based on 70 percent SO_2 removal efficiency when reusing the existing ESPs.

12.2.2 Coal Switching/Blending

Presented in table 12-9 are the 1985 coal analyses for the coal used at Cumberland and the alternative coal used to evaluate coal switching. The switch coal is low sulfur Kentucky coal having a sulfur content of 0.89 percent. Table 12-9 also presents the ESP plate area requirements for switching. This ESP plate area assumes that SO_3 conditioning will be used and that this reduces the overall required plate area needed by 25 percent.

TABLE 12-8. L/LS AND LSD FGD COSTS FOR CUMBERLAND PLANT (August 1987 Dollars)

Case Description	Overall Retrofit Factor	IAPCS Retrofit Costs[a]		
		Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.46	158.4-191.1	598-710	12.6-15.0
Boiler 2	1.40	149.1-179.5	575-686	12.1-14.6
LSD FGD (reuse ESP)				
Boiler 1	1.66	154.0	624	10.3
Boiler 2	1.32	129.0	555	9.2
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.43	140.6	492	10.8
Boiler 2	1.43	140.6	492	10.8

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

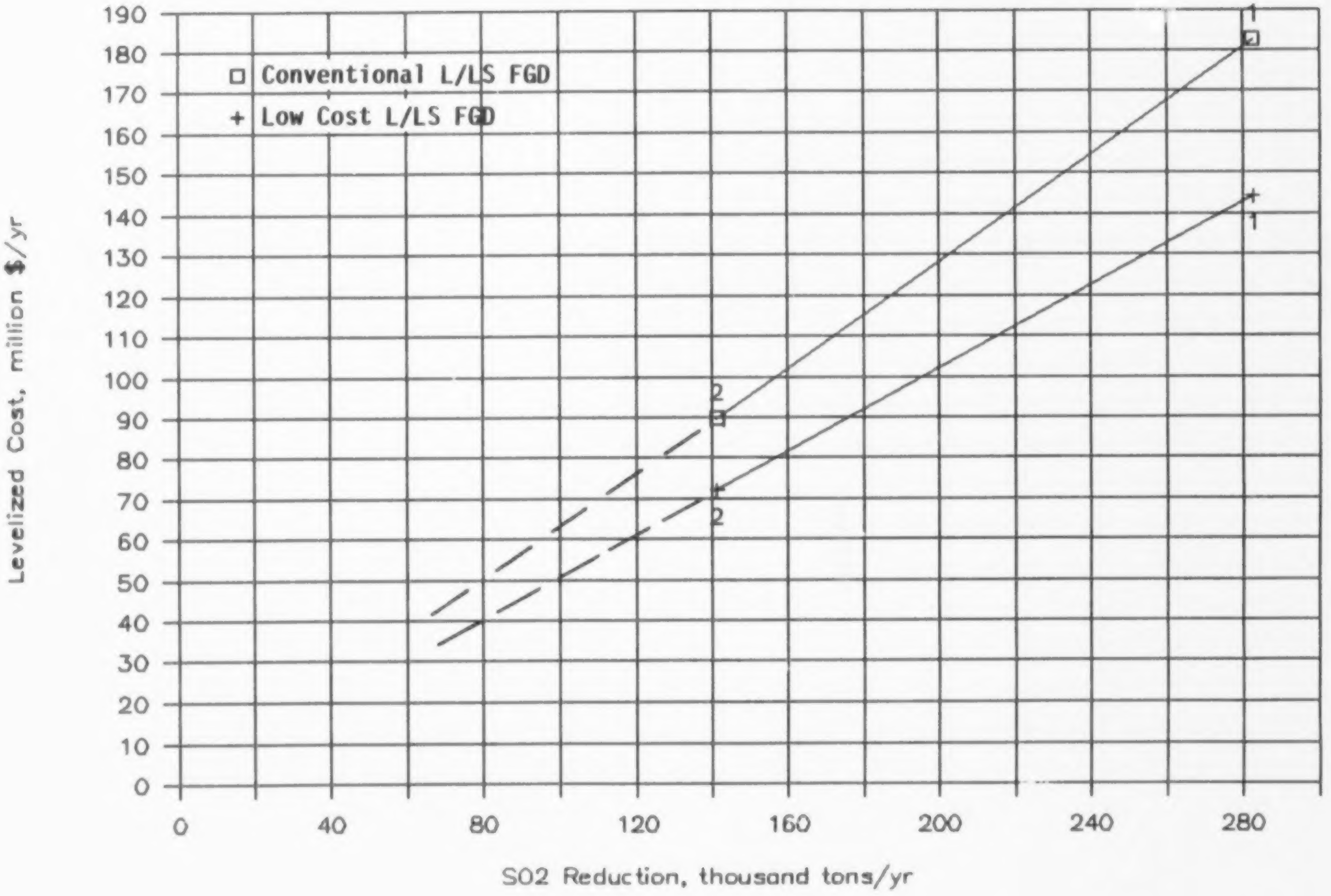

Figure 12-4. Cumberland Plant L/LS cost versus SO_2 reduction.

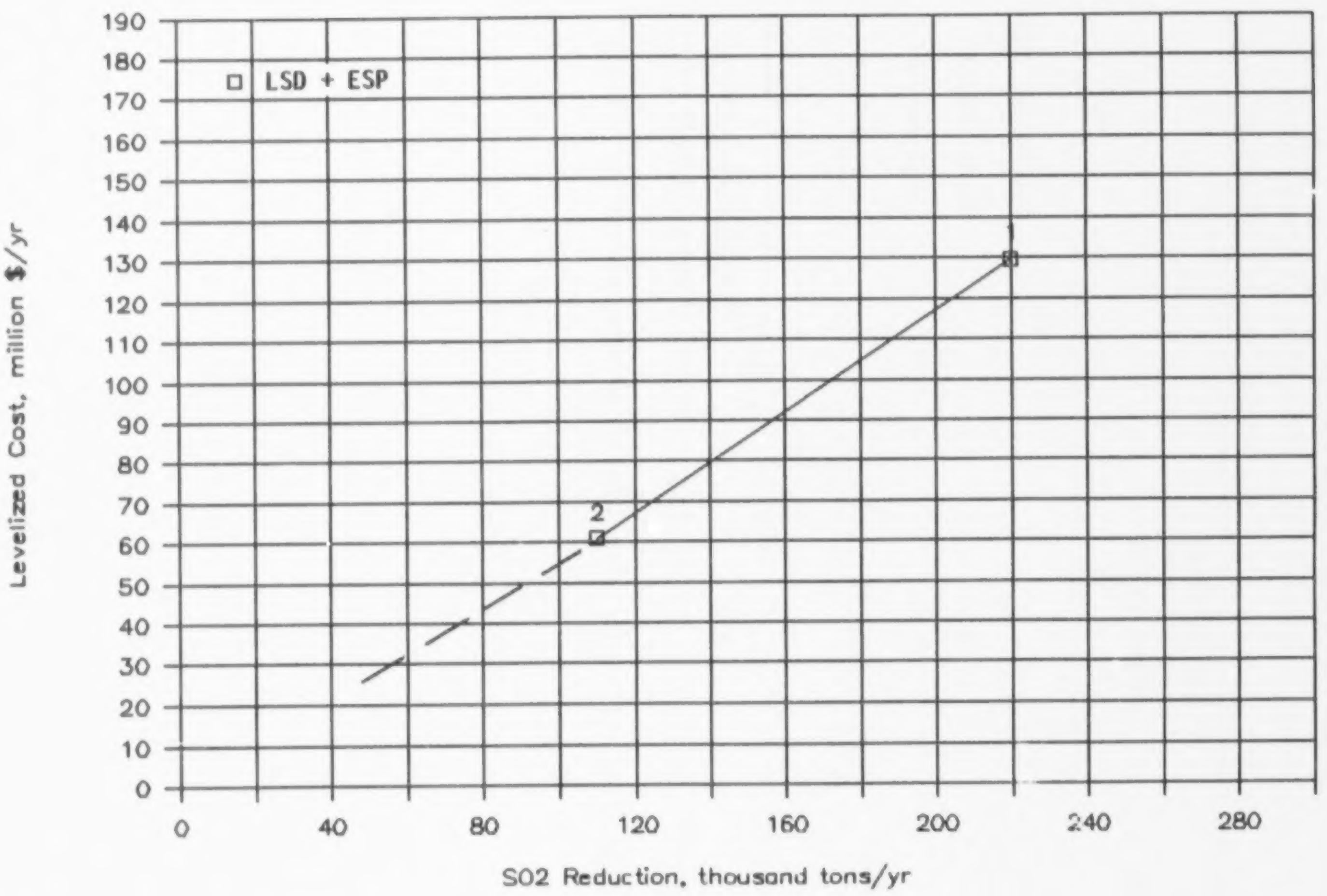

Figure 12-5. Cumberland Plant lime spray dryer FGD cost versus SO_2 reduction.

TABLE 12-9. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR THE CUMBERLAND STATION

Item	Existing Coal		Switch Coal	
	Boiler Number		Boiler Number	
	1	2	1	2
COAL PARAMETERS				
Percent Sulfur	2.8		0.89	
Percent Ash	9.3		13.4	
Btu Per Pound	11,643		11,587	
ESP SCA				
Existing/Needed SCA[a]	375		213	

[a] Specific collection area in ft^2/1000 acfm after SO_3 conditioning.

Figure 12-6 presents the plant level cost and emission reduction for switching to a low sulfur coal. Curves were generated to show the impact of different coal fuel price differentials. The lower curve represents a 1985 fuel price differential of $3.10 per ton between the existing coal and an eastern Kentucky low sulfur coal. The upper curve shows the impact of an additional fuel price differential of $15 per ton over the 1985 fuel price differential. Costs associated with each boiler for the rangae of fuel cost differential (FCD) are shown in table 12-10. Approximately 213,800 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.5 lb per million Btu SO_2 emission rate.

No costs are included for new particulate controls, new coal receiving segregation, and blending facilities. However, at Cumberland it is not anticipated that these facilities would be necessary.

TABLE 12-10. COAL SWITCHING COSTS FOR CUMBERLAND PLANT
(August 1987 Dollars)

		@ $3.10/ton FCD		@ $18.10/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1	106,900	189	3.0	809	13.0
2	106,900	189	3.0	809	13.0

12.2.3 Physical Coal Cleaning

Physical coal cleaning was not evaluated at Cumberland because the existing coal is already extensively washed and without detailed washability information, the cost of deeper coal cleaning could not be adequately addressed.

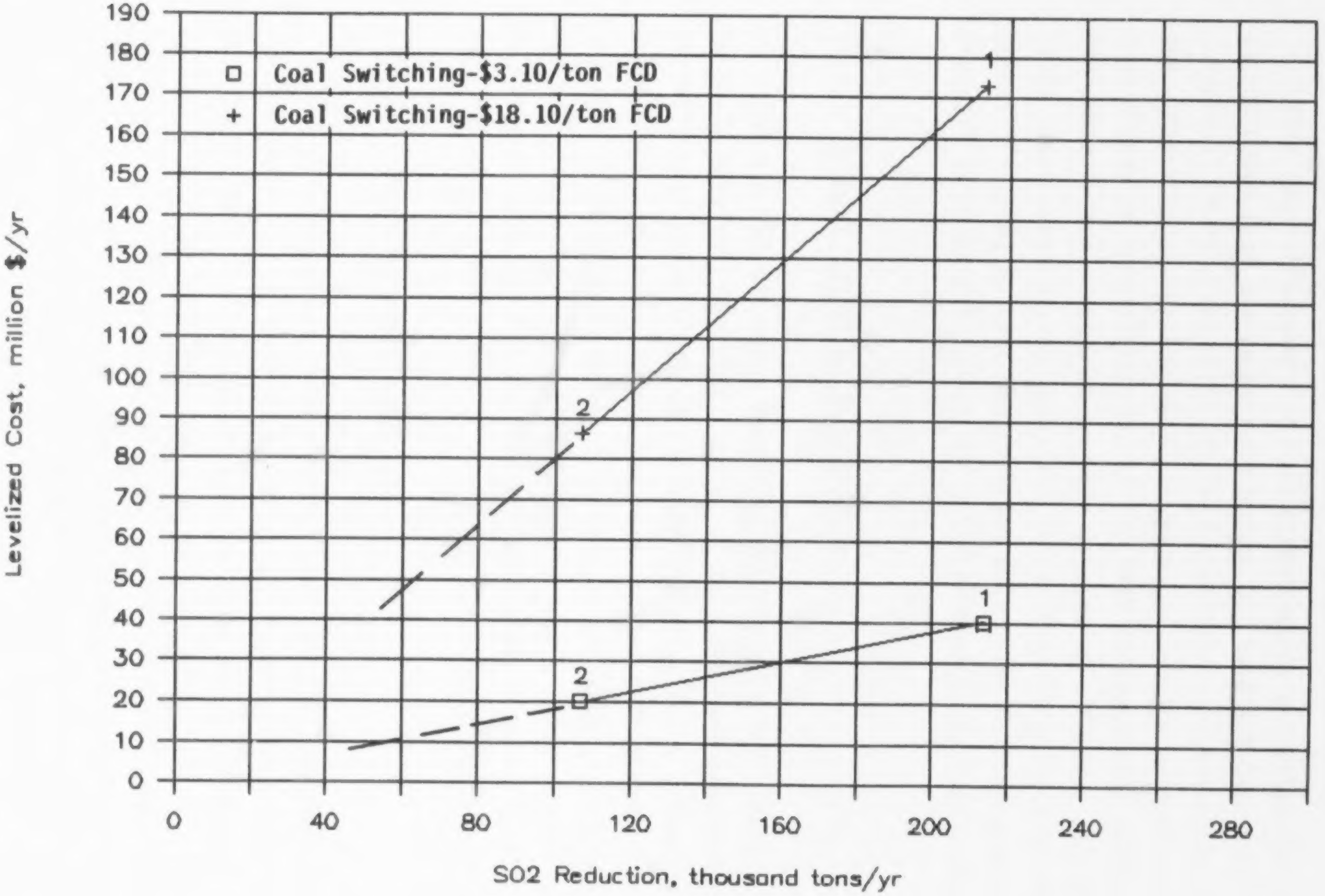

Figure 12-6. Cumberland Plant coal switching costs versus SO_2 reduction.

12.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data. The following control technologies were considered: furnace sorbent injection (FSI), duct spray drying (DSD) and retrofit applicability of fluidized bed combustion (FBC) or coal gasification (CG). The following discussion presents the retrofit issues and cost/performance estimates developed.

12.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. As such, many retrofit costs are built into the base case design and costs. Retrofit costs developed for these technologies focus primarily on costs for scope adders which are not in the base capital cost assumptions. These included railroad spur upgrades conversion of wet fly ash handling systems to dry handling/storage and added ESP plate area. Basic assumptions and cost adjustments made for FSI and DSD are presented in table 12-11. The following sections discuss the retrofit basis for each technology separately.

12.3.1.1 Furnace Sorbent Injection--

FSI technology was evaluated for both units at the Cumberland Station. The equipment layout is similar to the DSD layout except that furnace injectors rather than duct injectors would be used. Also, day bins would be located closer to each unit and a sorbent preparation area would be necessary. It is estimated that the retrofit ESPs at Cumberland would be adequate for particulate control after flue gas humidification. Because the old ESPs are still in place and operational, retrofit of FSI at Cumberland should pose no problems related to particulate control.

TABLE 12-11. SCOPE ADJUSTMENTS FOR FSI AND DSD AT CUMBERLAND PLANT

Item	Boiler 1	Boiler 2
BASIC ASSUMPTIONS		
Approximate access/congestion rank	Low	Low
Can the existing ESP be upgraded?	Yes	Yes
Was a new baghouse evaluated?	No	No
Distance to final waste disposal (miles)	1	1
SCOPE ADDERS COSTS[a]		
Install dry ash handling system (10^3 \$)[b]	\$9,341	\$9,341
New Stack	N/A[c]	N/A
Additional duct work (ft)[d]	0	0
Duct demo length (ft)[d]	0	0
Building demo area (ft^2)[d]	0	0
ADDER COSTS AND RETROFIT FACTOR SUMMARY		
Scope adder cost for new baghouse (10^3 \$)[a]	N/A	N/A
Scope adder costs for ESP reuse (10^3 \$)[a]	\$9,816	\$9,816
Baghouse retrofit difficulty factor	N/A	N/A
ESP upgrade retrofit difficulty factor (for plate area addition)	1.10	1.10

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[a] June 1985 dollars.

[b] Not applicable when a new baghouse is installed.

[c] N/A = Not applicable.

[d] Not applicable when the existing ESP is used.

12.3.1.2 Duct Spray Drying--

Duct spray drying using a lime slurry sorbent is evaluated for retrofit at Boilers 1 and 2. As for LSD FGD, it is assumed that the existing particulate control systems can be used with no upgrading, since both have excess capacity. It was assumed that sorbent would be injected into the old ESP boxes or in the flue gas ducting after the old ESPs. This would allow adequate time for SO_2 absorption and particulate drying to occur prior to particulate collection. The lime receiving/storage systems would be located in the same area as identified for LSD FGD.

12.3.1.3 Overall Retrofit Factors and Costs--

Table 12-12 presents the estimated retrofit costs for FSI and DSD. Figure 12-7 presents the cost of retrofitting FSI and DSD on boilers 1 and 2 versus the plant level SO_2 reductions achieved. For FSI, the two curves presented span the range of anticipated SO_2 removal (50 and 70 percent) and sorbent utilization (25 and 35 percent). SO_2 emissions are reduced by 156,800 tons per year under the 50 percent SO_2 removal case, and by 218,800 tons per year under the 70 percent SO_2 removal case. Plant-wide SO_2 emissions for DSD are reduced by 220,000 tons per year.

12.3.2 Fluid Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

Boiler units 1 and 2 were evaluated for repowering technologies. Since both units are significantly larger than 300 MW maximum and both boilers are relatively new with start-up in 1973, these units are poor candidates for FBC or CG retrofit.

12.4 NO_x CONTROL TECHNOLOGIES

NO_x controls evaluated at Cumberland include low NO_x burners/overfire air and selective catalytic reduction. The site-specific factors affecting performance and costs are discussed in the following sections.

TABLE 12-12. RETROFIT COSTS FOR FSI AND DSD FOR CUMBERLAND PLANT
(August 1987 Dollars)

Case Description	IAPCS Capital Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50% removal)[a]				
Boiler 1	48.5	7.6	647	78,400
Boiler 2	48.8	7.6	648	78,400
Furnace Injection (70% removal)[b]				
Boiler 1	49.7	7.7	469	109,700
Boiler 2	49.7	7.7	469	109,700
Duct Spray Drying (ESP reuse)				
Boiler 1	49.1	5.3	[illegible]	70,400
Boiler 2	49.1	5.3	438	70,400

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

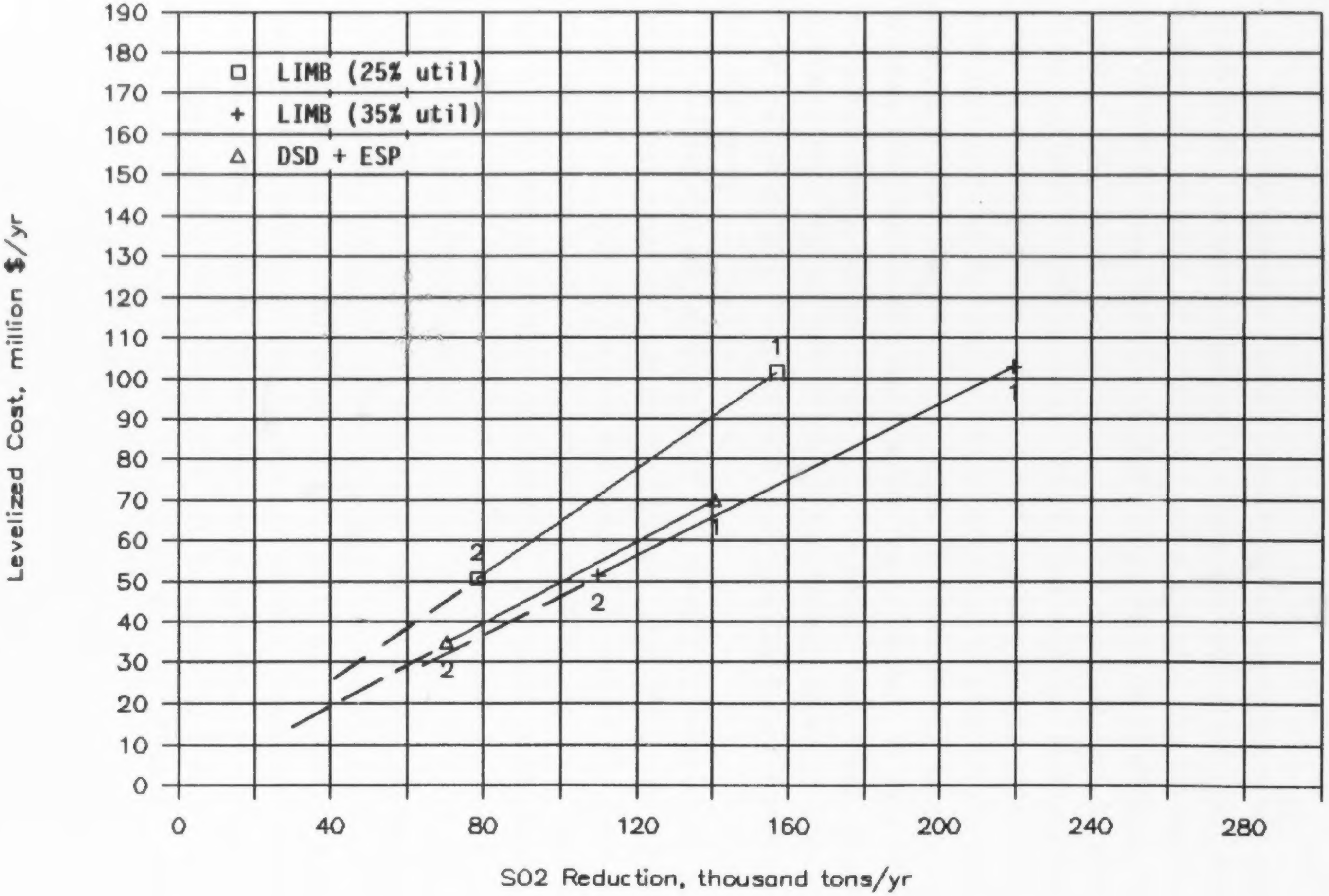

Figure 12-7. Cumberland Plant FSI/DSD cost versus SO_2 reduction.

12.4.1 Low NO_x Burners

The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls at the two Cumberland plant boilers are summarized in table 12-1. Units 1 and 2 are of a dry bottom, front wall-fired furnace design and, typically, would be candidates for low NO_x burners (LNB) retrofit. However, overfire air (OFA) may be better suited for these boilers for two reasons. First, the smallest vertical spacing between rows is possibly too narrow (4.8 feet) to accommodate LNB's. The narrow vertical spacing also results in an excessively high burner zone heat release rate (1,135,000 Btu/hr-ft^2), as shown in table 12-1. Second, the height between the furnace nose and the top row of burners is very high (85 feet); OFA ports easily can be installed. The burner heat input relative to the distance from the top burner row to the furnace nose, or exit, is moderate. This indicates that there is room above the top burner row for placement of the OFA ports.

For thermal NO_x effects, both the furnace volumetric and burner zone heat release rates (20,000 Btu/hr-ft^3 and 1,135 Btu/hr-ft^2, respectively) are very high for both wall-fired and tangential units. For fuel NO_x effects, the fuel nitrogen (N) and oxygen/nitrogen (O/N) ratio are unknown for units 1 and 2. The degree of flame interaction, evaluated by the burner heat input relative to the vertical burner spacing, though not so critical for an OFA retrofit, is high for LNB.

Finally, the plant did not report any slagging problems on units 1 and 2. This observation is supported by the intermediate excess air levels (20 percent). The coal burner in both units has a relatively high sulfur content (2.9 weight percent), possible creating some corrosion or tube wastage problems for a LNB or OFA system retrofit.

Based on the above discussion, it is estimated that a retrofit of LNB or OFA system applied to units 1 and 2 would exhibit a low NO_x reduction performance of 15-25 percent.

12.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700^{o}F for coal-fired systems require the SCR system location to bypass part of the economizer or use a tail-end system with flue gas preheat.

For units 1-2, it was assumed that the tail-end SCR system would be used to minimize unit down times. Boiler 1-2 flue gases would be diverted after passing through the ESPs to the preheater and through the catalyst. Hot flue gas from the reactor would be cooled before returning to the chimney. The catalytic reactors would be located behind each unit near each chimney.

Table 12-13 summarizes the SCR unit retrofit difficulty and scope adjustments for boiler units 1-2. The retrofit factor includes access and congestion, and underground obstruction considerations. A low retrofit factor was applied to the SCR costs at Cumberland units 1-2.

12.4.3 Summary of NO_x Control Costs

Table 12-14 and figure 12-8 present the annual cost of NO_x controls. Application of LNB or OFA is estimated to reduce NO_x emissions by 12,100 tons per year, at a cost of \$200 per ton of NO_x removed. Application of SCR would reduce NO_x emissions by 48,200 tons per year if 80 percent reduction can be achieved; the cost per ton of NO_x removed is \$3,346.

TABLE 12-13. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR CUMBERLAND PLANT
(August 1987 Dollars)

Item	Boiler 1	Boiler 2
Site access and congestion for SCR reactor	Low	Low
SCOPE ADDER PARAMETERS		
Building demolition (1,000$)	0	0
Ductwork demolition (1,000$)	185	185
New duct length (feet)	700	700
New duct costs (1,000$)	15,552	15,552
New heat exchanger (1,000$)	8,685	8,685
Total scope adder costs (1,000$)	24,423	24,423
Retrofit factor for SCR	1.16	1.16
General facilities (percent)	17	17

TABLE 12-14. NO_X CONTROLS COSTS FOR CUMBERLAND PLANT
(August 1987 Dollars)

NO_X Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X reduced (tons/yr)
Overfire Air	1	20	4.7	200	0.2	6,000
	2	20	4.7	200	0.2	5,100
Selective Catalytic Reduction	1	80	83.8	3,346	12.1	24,100
	2	80	83.8	3,346	12.1	24,100

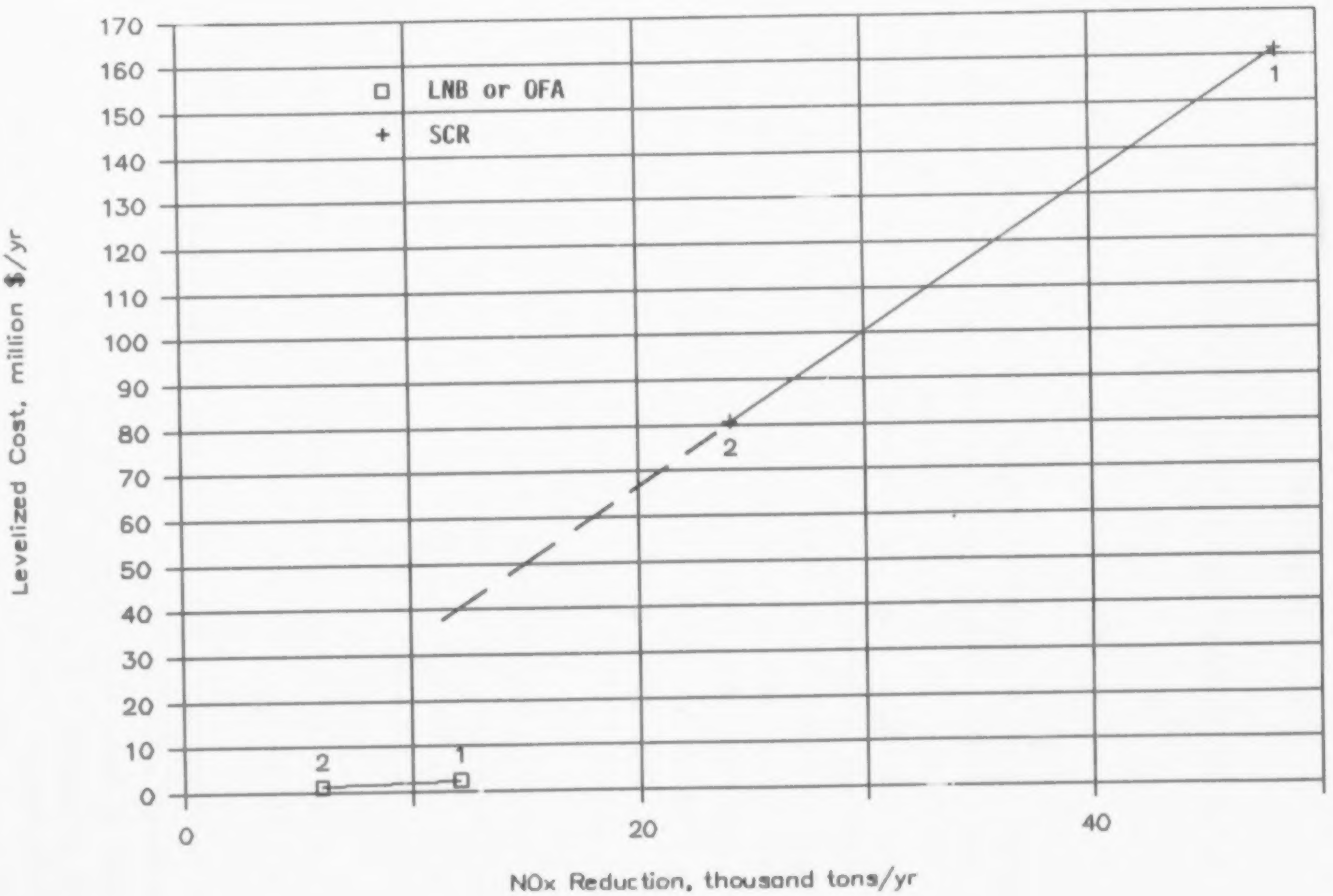

Figure 12-8. Cumberland Plant NO_x controls cost versus NO_x reduction.

SECTION 13

JOHNSONVILLE PLANT RETROFIT FACTORS AND COSTS

13.1 PLANT DESCRIPTION

The Johnsonville Plant, located in Humphreys County, Tennessee, is part of the Tennessee Valley Authority (TVA) system. With ten coal-fired boilers the plant has a total net generating capacity of 1,340 MW. Figure 13-1 shows the location of the power station, major associated auxiliary equipment, and support structures. To the north and northeast of the plant are large open areas. To the east and south the plant is bounded by the Tennessee River. To the west the plant is bounded by the plant electric transmission facilities, a rail spur, and an open area owned by TVA.

Table 13-1 presents key design and operational data for the existing equipment at the Johnsonville plant. Units 1 through 6 are 124 MW tangential-fired boilers (dry bottom ash). Units 7 through 10 are 149 MW front wall-fired boilers (dry bottom ash).

As with other TVA plants, coal is washed in a preparation plant prior to shipment to Johnsonville. All boilers burn the same medium-ulfur coal (1.7 dry weight-percent sulfur). The plant receives coal from eastern Kentucky and southern Illinois primarily at two barge unloading facilities. Coal is then conveyed to a single storage pile located to the north of the plant. Rail delivery facilities are also available. The coal storage area has a capacity of 90 days, but additional pile storage area can be created if needed.

Particulate emissions from all 10 boilers are controlled with electrostatic precipitators (ESPs). Each boiler has a separate ESP located on the powerhouse roof. Flue gases from all ESPs converge into a single duct and are routed to a 600-foot stack. An estimated 99 percent plus removal efficiency for particulate matter is reported for all units. The design ESP outlet flue gas temperature ranges from 300 to 325°F at peak load. ESPs for

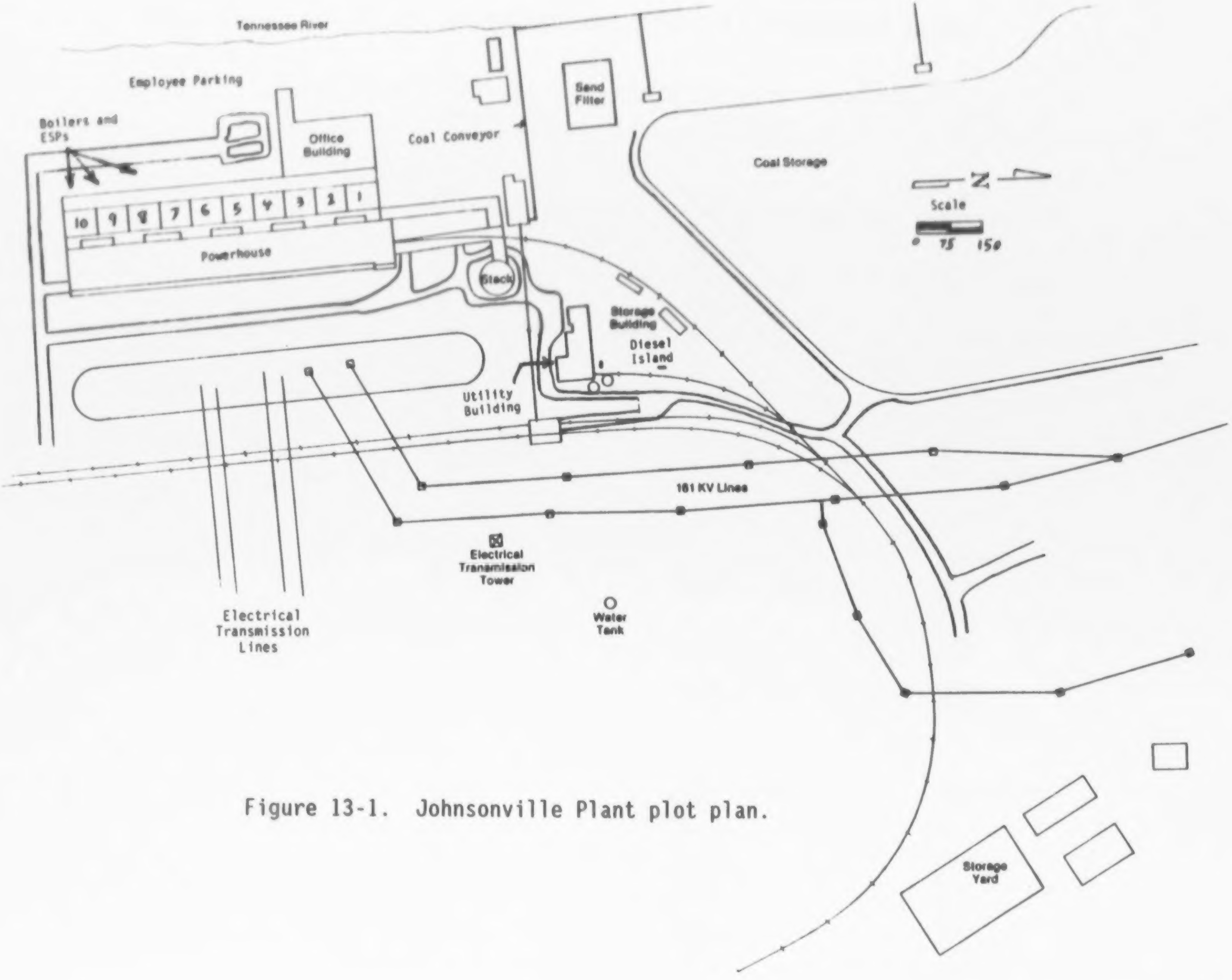

Figure 13-1. Johnsonville Plant plot plan.

TABLE 13-1. KEY DESIGN AND OPERATIONAL DATA FOR JOHNSONVILLE PLANT

Item	Boilers 1-4	Boilers 5-6	Boilers 7-10
BOILER AND STACK DATA			
Generating capacity (MW)	124	124	149
Boiler manufacturer	Combustion Engineering	Combustion Engineering	Foster Wheeler
Installation date	1951-52	1952-53	1958-59
Capacity factor (10 year projected)	38.6	30.35	41.3
Heat rate (Btu/kW-hr)	11,500	11,500	10,200
Boiler type/firing type/bottom type	Tangential/dry	Tangential/dry	Wall-fired/dry
Boiler dimensions, (ft, D x W x H[a])	25 x 34 x 62	25 x 34 x 62	25 x 42 x 50
Burner type/number of burners (# EL x #/EL)	Tangential/--[b]	Tangential/--[b]	Circular/4x4
Burner spacing (vert x horiz, ft)	--[b]	--[b]	6.5 x--[b]
Burner zone heat release rate (Btu/hr-ft^2)	297	297	284
Design oxygen level (percent O_2)/Excess Air	3.5/18	3.5/18	3.5/20
Draft type	--[b]	--[b]	Forced
Flue gas flow rate (1000 acfm @ °F)	5,732 @ 249°F	5,732 @ 294°F	5,732 @ 294°F
Stack size (height x diameter, feet)	600 x 32.5	600 x 32.5	600 x 32.5
Stack liner type	Epoxy Liner	Epoxy Liner	Epoxy Liner
FUEL AND SORBENT DATA			
Coal quality[c]			
Heat content (Btu/lb)	11,400	11,400	11,400
Volatile matter (percent)	28.1	28.1	28.1
Ash (percent)	12	12	12
Moisture (percent)	--	--[b]	--[b]
Sulfur (percent)	1.7	1.7	1.7
Nitrogen (percent)	1.73	1.73	1.73
Coal delivery methods			
Current	Barge	Barge	Barge
Design	Barge	Barge	Barge
Likely method for sorbent delivery			
PARTICULATE CONTROL EQUIPMENT DATA			
Type of control	ESP/cold side	ESP/cold side	ESP/cold side
New/retrofit control installation	1976	1976	1976
ESP specific collection area (ft^2/10^3 acfm)	266	266	211
Total plate area (10^3 ft^2)	127	127	110.9
Emission standards (lb/10^6 Btu)	0.1	0.1	0.1
ESP outlet emissions (lb/10^6 Btu)[d]	0.08	0.08	0.08
Design coal sulfur (percent)	2	2	3
Gas conditioning	None	None	None
Tested efficiency/design efficiency	99.2/99.6	99.2/99.6	99.2/99.6

(Continued)

TABLE 13-1. (CONTINUED)

Item	Boiler 1	Boiler 2	Boiler 3
NITROGEN OXIDE CONTROL EQUIPMENT DATA			
NO_x control equipment	None	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA			
SO_2 control equipment	None	None	None
SOLID WASTE DISPOSAL DATA			
Ash transport system type			
Boiler bottom ash	Wet sluice	Wet sluice	Wet sluice
ESP hoppers	Wet sluice	Wet sluice	Wet sluice
Ash disposal method	Pond, on-site	Pond, on-site	Pond, on-site
Existing pond capacity	2-3 years	2-3 years	2-3 years
Estimated distance to off-site waste disposal	1 mile	1 mile	1 mile

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

units 1 through 6 have an estimated specific collection plate area (SCA) of 266 $ft^2/10^3$ acfm, and were designed for a coal sulfur content of 2 percent. Unit numbers 7 through 10 have an estimated SCA of 211 $ft^2/10^3$ acfm, and were designed for a coal sulfur content of 3 percent.

Ash from the boilers, economizers, and ESPs for all units is sluiced to the ash sluice pond located west of the plant. The fly ash disposal site is almost filled to capacity; remaining life is about 2 to 3 years. Plant personnel indicated that the adjacent land to the northwest of the plant is being considered for an ash disposal pond.

13.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Johnsonville plant include lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching and physical coal cleaning. The following discussion presents the retrofit issues and cost/performance estimates for each.

13.2.1 Lime/Limestone and Lime Spray Drying FGD

13.2.1.1 Control Cases Evaluated--

Table 13-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. One shared control system was considered for the Johnsonville plant for the following reasons:

- flue gas from all the units already converge into a single duct to the north of the plant, making it neither practical nor cost effective to build a new independent ductwork system; and
- one large open area suitable for the absorbers is located close to the chimney and existing combined ductwork system.

TABLE 13-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR JOHNSONVILLE PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Removed (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
100 % Scrubbed	90	1.7	60,000
75 % Scrubbed	90	1.7	46,500
55 % Scrubbed	90	1.7	33,200
40 % Scrubbed	90	1.7	22,100
LSD FGD (new baghouse)			
100 % Scrubbed	86	1.7	57,500
75 % Scrubbed	86	1.7	44,700
55 % Scrubbed	86	1.7	31,900
40 % Scrubbed	86	1.7	21,300
LOW COST CONTROLS			
L/LS FGD			
Boilers 1-10	90	1.7	60,000

A single combined system would reduce the cost of the overall control system due to the economy of scale associated with shared components. Plant personnel indicated that the TVA has evaluated scenarios for partial scrubbing of the flue gas using a limestone forced oxidation system. In this report, the following partial scrubbing options are evaluated: 100, 75, 55, and 40 percent of the flue gas.

For LSD FGD, it is assumed that the ESPs cannot be reused for the following reasons:

- an excessive length of ductwork would be required to route the flue gas from the ESPs to the spray dryer area and then back to the ESPs again; and
- specific collection area is marginally sufficient to handle the increased particulate load and adding plate area to the roof-mounted ESPs would be difficult and costly.

For these reasons, LSD FGD system costs include the installation of a new baghouse. A waste disposal distance of one mile was assumed for all FGD cases.

13.2.1.2 Layout of Equipment and Design Basis--

Placement of the major components of the SO_2 control system is an important consideration in the development of retrofit factors and costs. Site specific access/congestion and other factors can complicate the placement of the control equipment, impacting retrofit cost. For each SO_2 control case considered, a simplified plant drawing or conceptual design has been prepared to illustrate the placement of the key components of each SO_2 control system. The placement of these components have been used in the development of retrofit difficulty and other retrofit cost considerations. Absorbers, spray dryers, ductwork, baghouses, clarifiers/vacuum filters, sorbent preparation, sorbent receiving, and storage, and FGD waste storage systems are shown on each drawing.

The following is a list of the drawings developed to illustrate the FGD control cases:

Figure Number	FGD Control Case Description
13-2	Conventional combined L/LS FGD system for all the units.
13-3	LSD FGD system for all the units (with new baghouse particulate control).

These drawings are not intended to represent the accuracy and detail associated with an engineering drawing but are approximately to scale. They are prepared from drawings supplied by the plant, sketches and measurements made during the plant visit, and photographs taken during the plant visit. Key site selection criteria were best satisfied by placing the majority of the control equipment in the open area to the north and northwest of the plant. This location is the first accessible point at which the combined flue gas from all boilers can be scrubbed. Therefore, it is the best location for the retrofit scrubber or spray dryer module. The utility building, storage area and diesel island are demolished and relocated to open more space for the sorbent separation area.

13.2.1.3 Scope Adjustments--

In order to retrofit a FGD system at Johnsonville, some of the existing equipment must be modified, and equipment not included in the IAPCS cost models must be added. These scope adjustments are summarized in Table 13-3 for all FGD cases.

The cost of converting the ESPs ash removal and conveyance system from wet to a dry system is included. Dry waste is necessary for conventional L/LS FGD sludge stabilization but not for the forced oxidation LSD FGD with a new baghouse case.

The cost of a new baghouse was included for LSD FGD in the IAPCS costs, because existing ESPs cannot be easily reused or upgraded. A new rail spur was installed to allow sorbent unloading operations to be separated from coal unloading operations. The cost of an estimated 1,200 ft of new rail lines was included for sorbent unloading operations at 1 x 10^6 dollars per mile (ConRail, 1986).

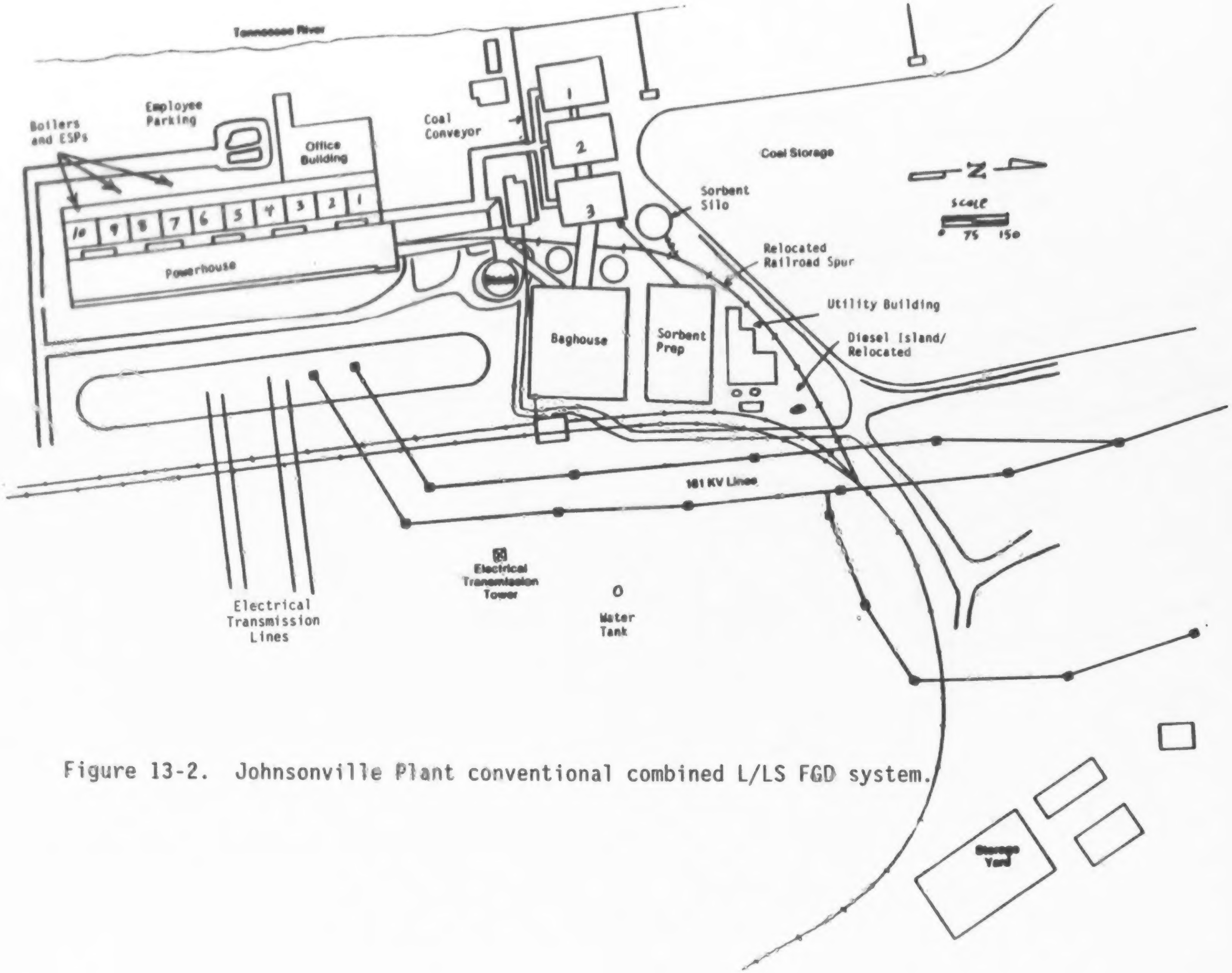

Figure 13-2. Johnsonville Plant conventional combined L/LS FGD system.

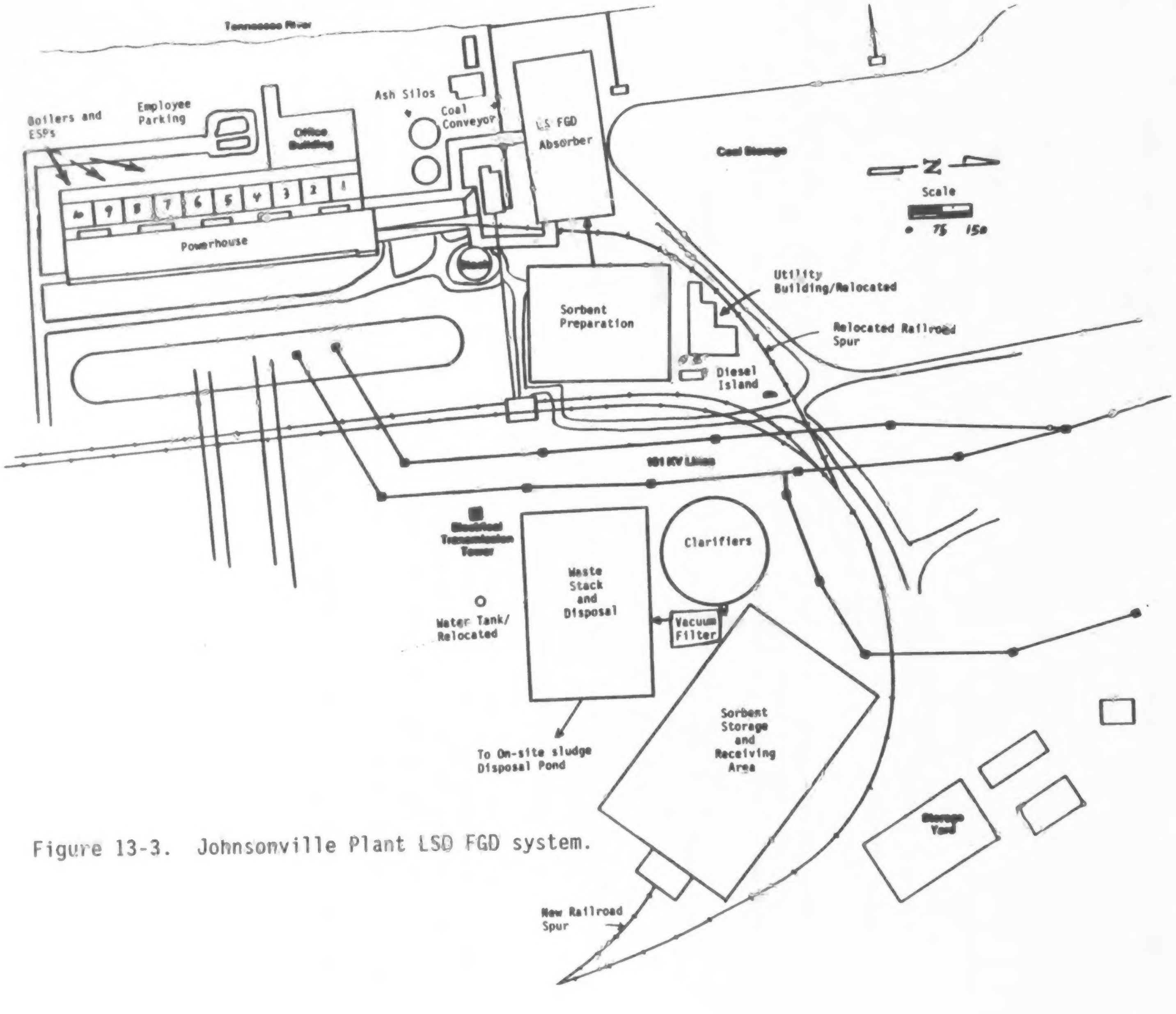

Figure 13-3. Johnsonville Plant LSD FGD system.

TABLE 13-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR JOHNSONVILLE PLANT

Scope Adjustment	Description[a]
• Modify draft controls	Balanced draft controls would likely be required with new SO_2 control systems to prevent large negative pressure surges in furnace ($1.20/kW).
• Building demolition/ductwork demolition/electrical diesel island demolition	Demolition and relocation costs were added for placement of equipment as necessary for all FGD cases ($0.67/kW).
• Ash removal/conveyance modification	The ESP ash discharge systems for conventional L/LS FGD were changed from wet sluice to dry for sludge stabilization ($7.27/kW).
• Stack relining	It was assumed necessary to reline existing steel stacks to prevent corrosion for L/LS FGD ($40/$ft^2$).
• New rails	A new rail spur would be installed to allow sorbent unloading operations to be separate from coal unloading operations for all FGD cases ($1 x 10^6/mile).

[a] Except for rail costs, the adder costs shown in brackets are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit and other considerations.

The costs for balanced draft controls, for building, electrical, and duct demolition, and for stack relining are based on EPRI guidelines. The costs to relocate the utility building, diesel island, water tower and any plant roads are accounted for in the general facilities cost. For all cases, a general facilities factor of 5 percent was used. The demolition cost for the utility building assumes the 18,000 ft^2 building has a concrete foundation, two stories which includes mechanical, plumbing, and electrical equipment. For the diesel island, 200 feet of 6 to 8 inch carbon steel pipe was estimated for demolition and relocation.

13.2.1.4 Location and Retrofit Factors--

Tables 13-4 and 13-5 present the location and retrofit factors used for L/LS and LSD FGD. The aggregate location factor presented in the column titled LOCF incorporates the following factors: seismic zone factor of 2.0, climate factor of 0.99, and labor and productivity and materials factor of 0.95 (Tennessee). Relatively high soils factors have been used, since the plant's riverside location would tend to increase control costs significantly over the base case. Table 13-4 also summarizes the retrofit factors for the combined boiler case.

Table 13-6 presents the duct tie-in distances between process areas used. In general, medium length duct runs for flue gas handling are necessary to route around the coal handling structures. The distances from waste processing and sorbent preparation to the absorbers are shown in the table for the FGD cases evaluated.

Because a significant amount of free space adjacent to the stack allows fairly standard control system configurations, low access/congestion retrofit factors were used to adjust the cost of major FGD system components. The underground obstruction factor adjusts the base cost for subsurface interferences, and generally, low factors were used. Contributing to the low underground obstruction factors used include the following factors: (1) the FGD facilities were located away from the boiler/turbine area in a location where there are no circulating water pipes, gas mains, and duct banks.

TABLE 13-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR JOHNSONVILLE PLANT

Item	All Units LOCF[a]	RETROFIT FACTORS Boilers 1-10 UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	0.97	1.06	1.05	1.00	1.11
SO_2 Removal	0.95	1.00	1.10	1.00	1.10
Flue Gas Handling	0.98	1.01	1.50	1.35	2.05
Waste Handling	0.97	1.14	1.05	1.06	1.27
General Support Equipment	0.97	1.01	1.24	1.00	1.25
SCOPE ADJUSTMENTS					
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00
Chimney	NA	NA	NA	NA	NA
Demolition	0.95	1.00	1.00	1.00	1.00
Draft Controls	0.95	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES					
Engineering - %			11		
General Facilities - %			5		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 13-6 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 13-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR JOHNSONVILLE PLANT

Item	All Units	RETROFIT FACTORS Boilers 1-10			
	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT					
Reagent Feed	1.18	1.06	1.05	1.00	1.11
SO_2 Removal	1.03	1.00	1.10	1.00	1.10
Flue Gas Handling	1.15	1.03	1.50	1.65	2.55
General Support Equipment	1.16	1.01	1.24	1.00	1.25
SCOPE ADJUSTMENTS					
New Ash Silo System	N/A	N/A	N/A	N/A	N/A
Chimney	N/A	N/A	N/A	N/A	N/A
Baghouse	1.03	1.13	1.10	1.00	1.24
ESP Plate Addition	N/A	N/A	N/A	N/A	N/A
Demolition	0.95	1.00	1.00	1.00	1.00
Draft Controls	0.95	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES					
Engineering - %			11		
General Facilities - %			5		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 13-6 for distance assumptions.

[e] AGGF = Aggregate Factor.
N/A = Not applicable.

TABLE 13-6. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR JOHNSONVILLE PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
L/LS FGD	200	300	50	1,000
LSD FGD (new baghouse)	400	400	50	N/A[c]

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

13.2.1.5 Overall Retrofit Factors and Costs--

Table 13-7 presents the overall retrofit factors and costs for all FGD cases evaluated at the Johnsonville plant. The range of costs shown for L/LS FGD reflect the different process options evaluated: limestone with adipic acid; lime with MgO addition and conventional lime/limestone FGD. The EPRI overall retrofit factor shown is determined by dividing the EPRI retrofit capital cost by the EPRI base capital cost (after adjusting for process factors as described above).

Figures 13-4 and 13-5 summarize the plant level costs of installing L/LS and LSD FGD. The data point labeled low cost on figure 13-4 shows the impact of scrubber optimization by eliminating the spare towers and maximizing the tower SCR, which along with the use of adipic acid additives, minimizes capital cost.

The application of L/LS FGD would reduce plant level SO_2 emissions by approximately 60,000 tons per year assuming a 90 percent level of control. Application of LSD FGD at all units would reduce plant level SO_2 emissions by approximately 57,500 tons per year.

13.2.2 Coal Switching and Cleaning

These technologies were not evaluated for boilers having small roof mounted ESPs. Adding additional plate area is not possible, and the use of SO_3 conditioning is likely to be marginally beneficent.

13.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data. For the Johnsonville plant the following control technologies were initially considered: furnace sorbent injection (FSI), duct spray drying (DSD) and

TABLE 13-7 L/LS AND LSD FGD COSTS FOR JOHNSONVILLE PLANT
(August 1987 Dollars)

		IAPCS Retrofit Costs[a]		
Case Description	Overall Retrofit Factor	Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD Boilers 1-10	1.48	151.2-183.3	1,213-1,433	16.7-19.7
LSD FGD (new baghouse) Boilers 1-10	1.82[b]	200.4	1,350	17.9
LOW COST CONTROL SYSTEMS				
L/LS FGD Boilers 1-10	1.48	136.2	993	14.2

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] Retrofit factor includes impact of new fabric filter.

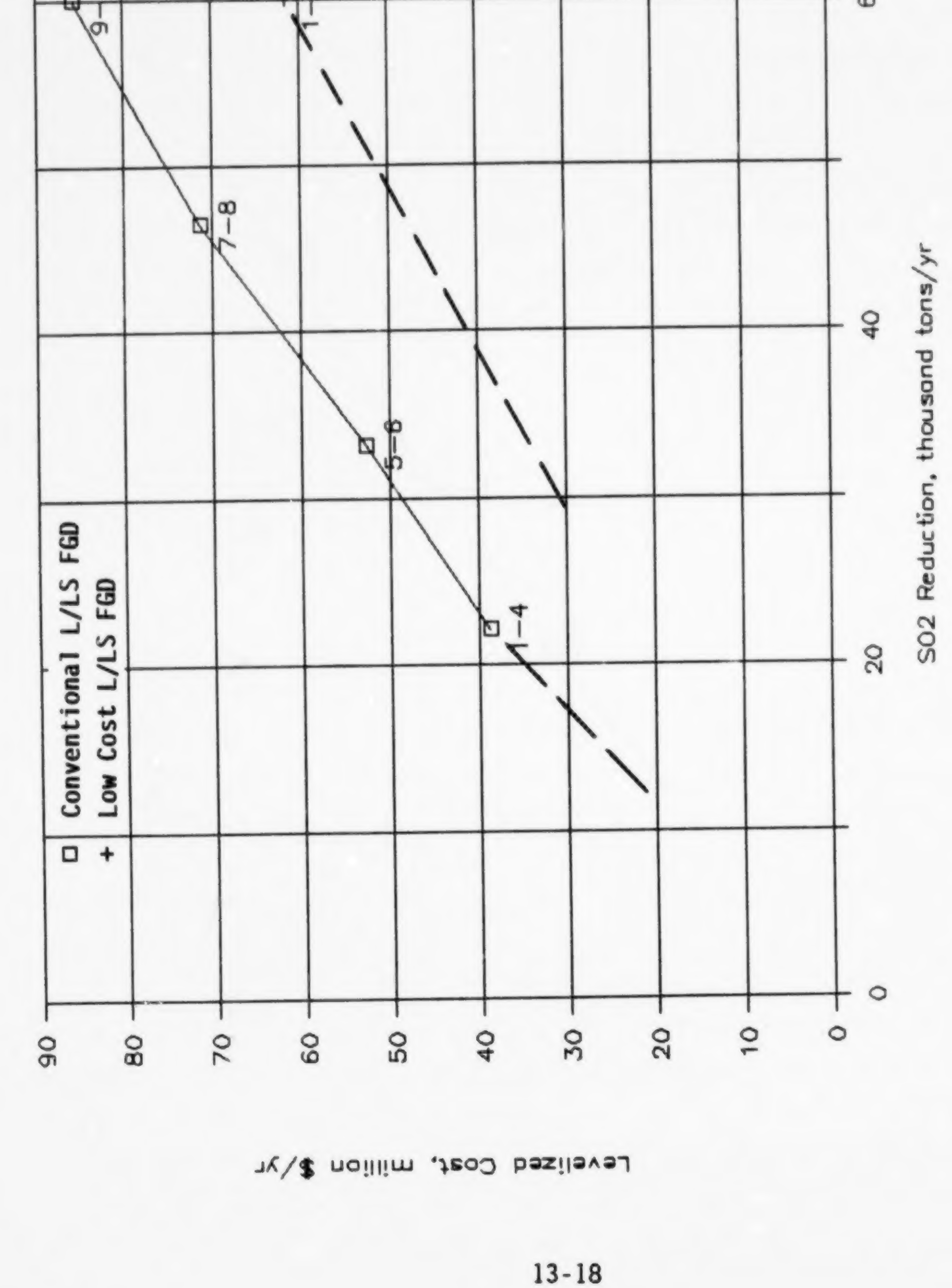

Figure 13-4. Johnsonville Plant L/LS cost versus SO_2 reduction.

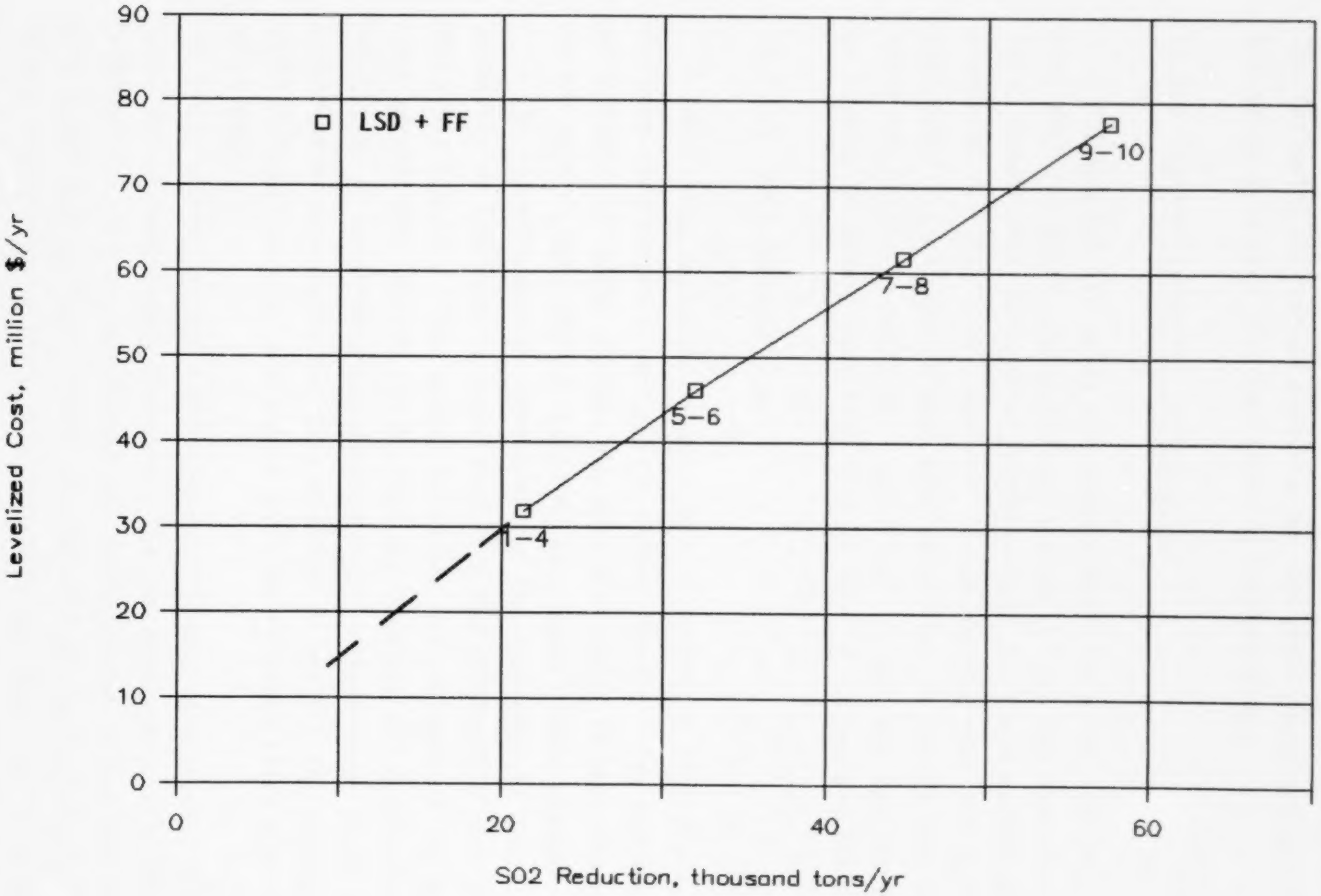

Figure 13-5. Johnsonville Plant lime spray dryer FGD cost versus SO_2 reduction.

fluid bed combustion (FBC) or coal gasification (CG) retrofit/life extension. The following discussion presents the retrofit issues and cost/performance estimates developed for the remaining technologies.

13.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. Many retrofit costs, consequently, are built into the base case design costs. Basic assumptions and cost adjustments made for these technologies are presented in table 13-8. However, it was decided that the boiler units at Johnsonville would not be good candidates for FSI, since roof mounted ESPs could not easily be upgraded. Specifically, the roof may not be able safely to support necessary additions such as humidification and ESP tuneup.

13.3.1.1 Duct Spray Drying--

Duct spray drying is accomplished by injection lime slurry in the ductwork upstream of a particulate control device. The concept is the same as conventional spray drying; the main difference is that the residence time in the duct is much shorter compared to a spray drying chamber.

The retrofit factors developed for the Johnsonville plant focus primarily on DSD factors associated with the particulate control equipment and scope adders. Scope adders which are not included in the base capital cost assumptions include new particulate controls and demolition and relocation of existing equipment/buildings. These adder costs and the technologies base costs are then adjusted to reflect the site-specific access/congestion and underground obstruction costs using EPRI methodology and factors.

Cost adders include the following: (1) duct demolition, (2) new rail line, and (3) additional ductwork. The new baghouse cost is included in the IAPCS model. The process layout and configuration is similar to the LSD FGD case considered earlier in this section with the exception of the diesel island and utility building demolition are not required. Therefore, the baghouse, rail repair, and flue gas handling area retrofit costs for LSD FGD

TABLE 13-8. SCOPE ADJUSTMENTS FOR DSD AT JOHNSONVILLE PLANT

Item	Boilers
	Combined System for Units 1-10
BASIC ASSUMPTIONS	
Approximate access/congestion rank	Medium
Is new particulate collector required (baghouse)?	Yes
Distance to final waste disposal (miles)	<1
SCOPE ADDERS	
New railroad spur (ft)	1,000
Additional duct work (ft)	800
Duct demolition length (ft)	150
ADDER COSTS AND RETROFIT FACTOR SUMMARY	
Total scope adders cost (10^3 \$)[a]	18,429
Baghouse retrofit difficulty factor	1.24

[a] June 1985 dollars.

are used here for similar considerations. Demolition cost was estimated using EPRI methodology.

13.3.1.2 Overall Retrofit Factors and Costs--

Table 13-9 presents the estimated retrofit costs for DSD. Figure 13-6 presents the cost of retrofitting DSD on boilers 1-10 versus the plant level of SO_2 reductions achieved. Plant-wide SO_2 emissions for DSD would be reduced by 44,900 tons per year with retrofit of DSD with a new fabric filter.

13.3.2 Fluid Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

All of the Johnsonville units are potential candidates for FBC or CG retrofit. Boilers 1-6 have low capacity factors and poor heat rates and have been in service over 35 years. This, coupled with the availability of space east of the boiler buildings and the poor retrofit potential of FSI and DSD with ESP reuse, make the boilers good candidates for life extension through FBC or CG retrofit. Boilers 7-10 have better heat rates and higher capacity factors but are also poor candidates for retrofit of the other low cost SO_2 controls. As such, the boilers also have good potential for retrofit of FBC or CG.

13.4 NO_x CONTROL TECHNOLOGIES

This section presents the cost and performance estimates developed for NO_x controls at the Johnsonville plant. Control applicability and performance are discussed in the following sections for each boiler. The controls considered are as follows: low NO_x burners and overfire air, and selective catalytic reduction. The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls at the ten Johnsonville plant boilers are discussed in the following sections.

TABLE 13-9. RETROFIT COSTS FOR DSD FOR JOHNSONVILLE PLANT (August 1987 Dollars)

Case Description	IAPCS Capital Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Duct Spray Drying (new baghouse) Boilers 1-10	120.7	11.8	1,141	44,900

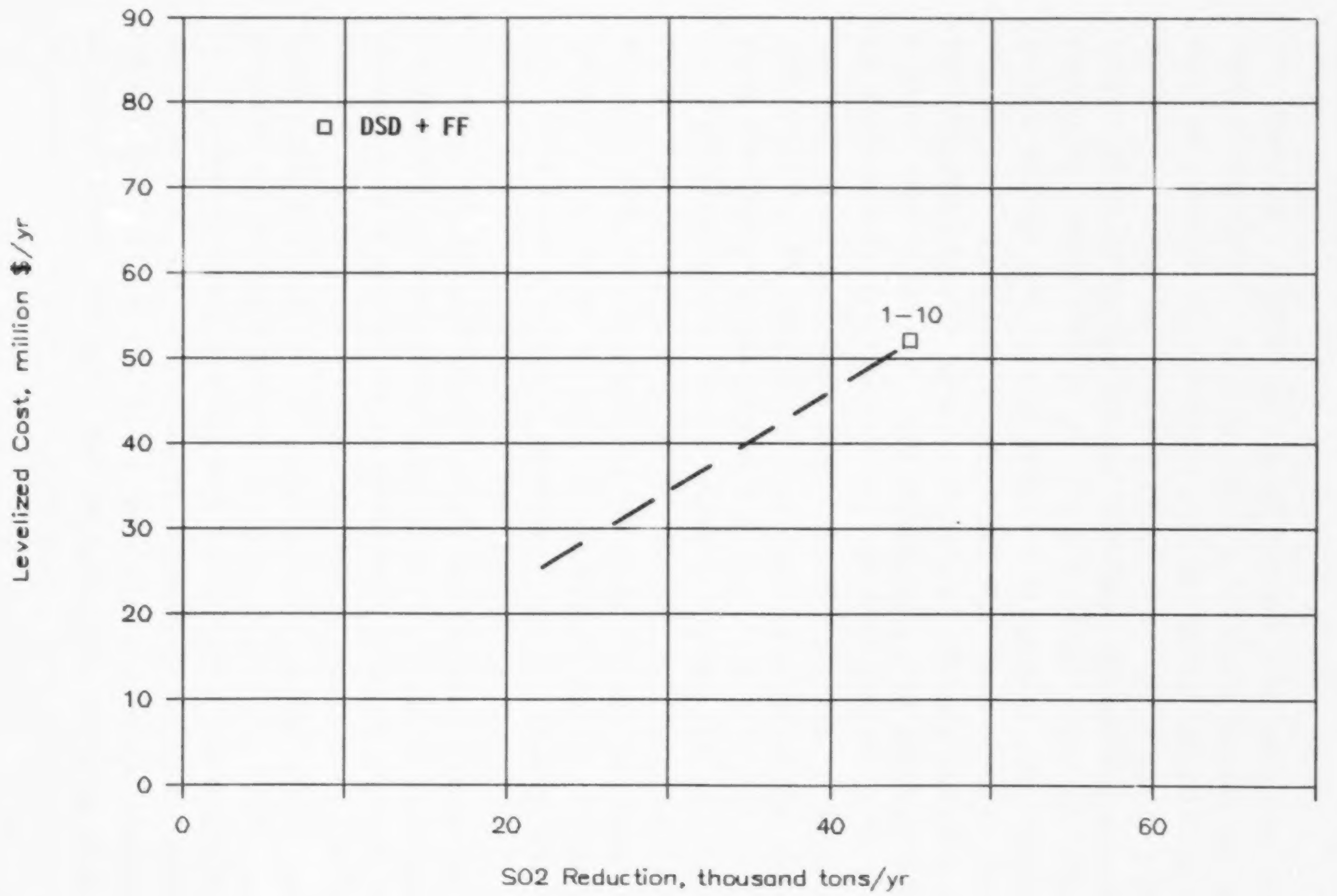

Figure 13-6 Johnsonville Plant FSI/DSD cost versus SO_2 reduction.

13.4.1 Low NO_x Burners

Overfire Air (OFA) and Low NO_x Burners (LNB) were evaluated for the Johnsonville units. The site-specific factors affecting the performance and costs of retrofit NO_x combustion controls at the ten Johnsonville plant boilers are summarized in Table 13-1. Units 1 to 6 are of a dry bottom, tangential-fired furnace design; therefore, OFA was the combustion control considered. Units 7 to 10 are of a dry bottom, front wall-fired furnace design, and for this type of unit, low NO_x burners (LNB) were evaluated.

Units 7-10 are each 149 MW, front wall-fired boilers. Both boilers are equipped with circular burners; therefore, LNBs are available for this type of unit. The burner heat input (approximately 88 million Btu/hr) relative to the furnace depth (25 feet) is very low for a wall-fired unit. Therefore, rear wall flame impingement should not be a problem for a LNB retrofit at Johnsonville 7-10. The burner heat input relative to the furnace height above the top burner row is moderate.

This characteristic is reflected in the nonvolatile fraction of the boiler heat input flux (180 million Btu/sec^2-ft^2) relative to the furnace residence time (1.5 seconds) and the upper furnace residence time (0.68 seconds). The ratios are moderate, indicating residence time is somewhat low (i.e., the furnace volume is moderate). This is shown by the intermediate furnace volumetric heat release rate (27,000 Btu/hr-ft^3).

Since the furnace overall height and the height above the top burner row are moderately large, flame impingement on the superheater/reheater tubes should not be a problem for a LNB retrofit at Johnsonville Units 7-10. However, with the narrow furnace and the intermediate to low volatility coal, there could be potential for carbon burnout problems with a low NO_x burner retrofit. This impact would be minimized by the large furnace depth.

No coal slagging problems were identified at Johnsonville 7-10. This may be due, in part, to the low-to-intermediate excess air operating level (20 percent). If the coal has a low slagging tendency, there may be additional excess air margin for LNB operation, promoting greater NO_x reductions.

Considering all the above factors, it appears that Johnsonville units 7-10 would exhibit a high NO_x reduction performance with a LNB retrofit. The LNB retrofit NO_x reduction performance is estimated at 50 percent which is the maximum anticipated NO_x reduction level for LNB.

Units 1 to 6 are each 124 MW, which are relatively small sizes for tangential-fired units. Influence of unit size on NO_x reduction performance of a retrofit OFA system can be examined in several ways. The bulk and upper furnace residences times can be estimated by dividing the total furnace height and the top burner row/furnace exit distance by the bulk furnace gas velocity, respectively. Residence times available for completing combustion at the six boilers are low, thus increasing the potential for carbon burnout problems and limiting the retrofit OFA system NO_x reduction performance. For thermal NO_x effects, although not as critical for tangential units, both the furnace volumetric and burner zone heat release rates of Units 1 to 6 (23,000 Btu/hr-ft^3 and 297,000 Btu/hr-ft^2, respectively) are moderately high.

Although the fuel nitrogen (1.7 weight-percent) is fairly high, the fuel oxygen/nitrogen ratio (2.0) is very low with less fuel-bound oxygen in intimate contact with the fuel nitrogen. The local reducing conditions created by OFA combustion staging would affect a large fraction of the fuel nitrogen, potentially increasing NO_x reductions.

Finally, the plant indicated no significant slagging problems on units 1-6. This observation is supported by the intermediate excess air levels (20 percent). The coal burned in Units 1 to 6 has a relatively low-sulfur content (1.7 weight-percent), possibly creating little or no corrosion or tube wastage problems for an OFA system retrofit.

Based on the above discussion, it was estimated that a retrofit OFA system applied to all six boilers would exhibit an intermediate NO_x reduction performance of 25 percent, this performance level being based on balancing the low slagging tendency of the coal and low fuel NO_x effects.

13.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700°F for coal-fired systems require the SCR system location to bypass part of the economizer or use a tail-end system with flue gas reheat.

For units 1-10 it was assumed that the tail-end SCR system would be used to minimize unit down times and to benefit from economies-of-scale. Boiler 1-10 flue gases would be diverted from the flue gas duct just before the chimney to the reheater and through the catalyst bed. Hot flue gas from the reactor would be cooled in the reheater before returning to the chimney.

Table 13-10 summarizes the SCR unit retrofit difficulty and scope adjustments for boiler units 1-10. The retrofit factor includes access and congestion, and underground obstruction considerations. A low retrofit factor was applied to the SCR costs because sufficient space is available between the chimney and the coal handling facilities. However, if an FGD system is also installed, the SCR retrofit difficulty factors would be high.

13.4.3 Summary of NO_x Controls Costs

Table 13-11 and figure 13-8 present the annual cost of NO_x controls. The unit cost of LNC at boilers 1-10 was estimated to be $370 to $427 per ton of NO_x removed. Application of LNB at units 7-10 and OFA at units 1-6 would reduce NO_x emissions by 6,600 tons per year. Application of SCR would reduce NO_x emissions by 11,400 tons per year if 80 percent reduction can be achieved; the cost per ton of NO_x removed is $2,428.

TABLE 13-10. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR JOHNSONVILLE PLANT (August 1987 Dollars)

	Boilers 1-10
Site access and congestion for SCR reactor	Low
SCOPE ADDER PARAMETERS	
Building demolition (1,000$)	0
Ductwork demolition (1,000$)	205
New duct length (feet)	500
New duct costs (1,000$)	12,013
New heat exchanger (1,000$)	9,411
Total scope adder costs (1,000$)	21,628
Retrofit factor for SCR	1.16
General facilities (percent)	13

TABLE 13-11. NO_X CONTROLS COSTS FOR JOHNSONVILLE PLANT

(August 1987 Dollars)

NO_X Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Annual Cost (mills/kWh)	NO_x Reduced (tons/year)
Low NO_x Burner	1	25	4.6	370	0.3	300
	2	25	4.6	370	0.3	300
	3	25	4.6	370	0.3	300
	4	25	4.6	370	0.3	300
	5	25	4.6	370	0.3	300
	6	25	4.6	370	0.3	300
	7	50	17.0	427	1.0	1,200
	8	50	17.0	427	1.0	1,200
	9	50	17.0	427	1.0	1,200
	10	50	17.0	427	1.0	1,200
Selective Catalytic Reduction	1-10	80	82.9	2,428	6.4	11,400

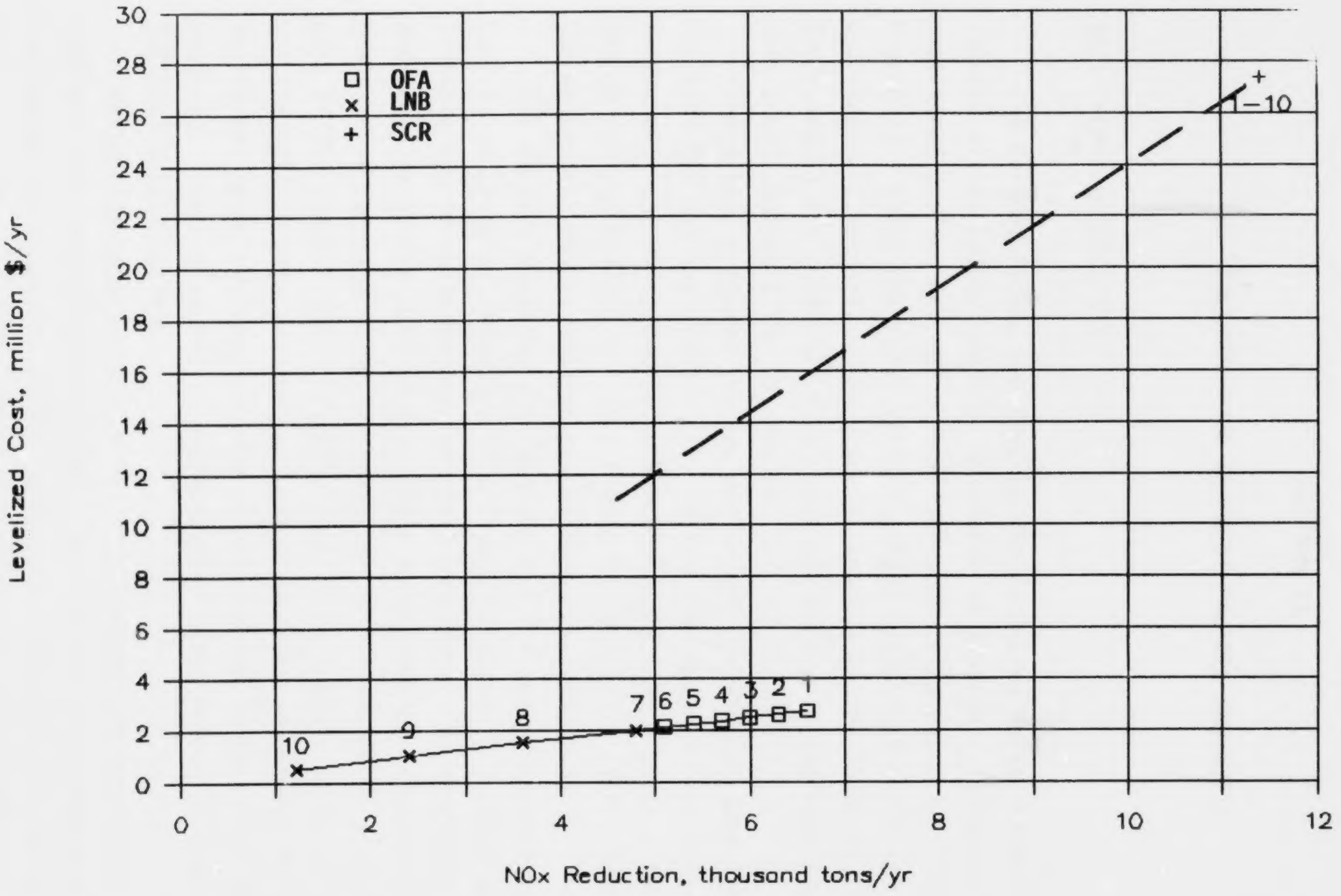

Figure 13-7. Johnsonville Plant NO_x controls cost versus NO_x reduction.

SECTION 14

COLBERT PLANT RETROFIT FACTORS AND COSTS

14.1 PLANT DESCRIPTION

The Colbert Plant, operated by the Tennessee Valley Authority (TVA), is located within Colbert County, northwest of Alabama. The plant contains five coal-fired boilers and has a total net generating capacity of 1,272 MW. Figure 14-1 shows the power station, major associated auxiliary equipment, and support structures. The plant is bounded to the north by the Tennessee River and to the south by utility transformers. To the west and east are open areas, suitable for SO_2 control systems placement.

Table 14-1 presents the key design and operational data obtained from EIA form 767 and the plant visit. All boiler units are wall-fired (dry bottom ash) and manufactured by Babcock and Wilcox. Units 1 through 4 are 200 MW (gross) boilers and were placed in service in 1955. Unit 5 is a 550 MW (gross) boiler and was placed in service in 1965.

All boilers burn the same medium, 2.3 dry weight-percent sulfur coal. Coal is received by Tennessee River barge shipments from Ohio and Southern Illinois and is unloaded by clam shell unloaders. No unloading facilities presently exist for rail lines. After being crushed to one-half inch size, the coal is conveyed either directly to the boilers or to a coal pile on the east of the plant. Both unloading facilities operate 11 to 12 hours a day, and the coal storage area has a storage capacity of between 60 and 90 days. Additional space for coal storage can be created if more coal volume is required. Coal is washed in a preparation plant before shipment to meet the TVA coal specifications.

Particulate emissions from all five boilers are controlled with electrostatic precipitators (ESPs). Each boiler has a separate ESP which is located on the riverside of the powerhouse. The ESPs for units 1 through 4 have a specific collection plate area (SCA) of 175 $ft^2/10^3$ acfm. The ESPs

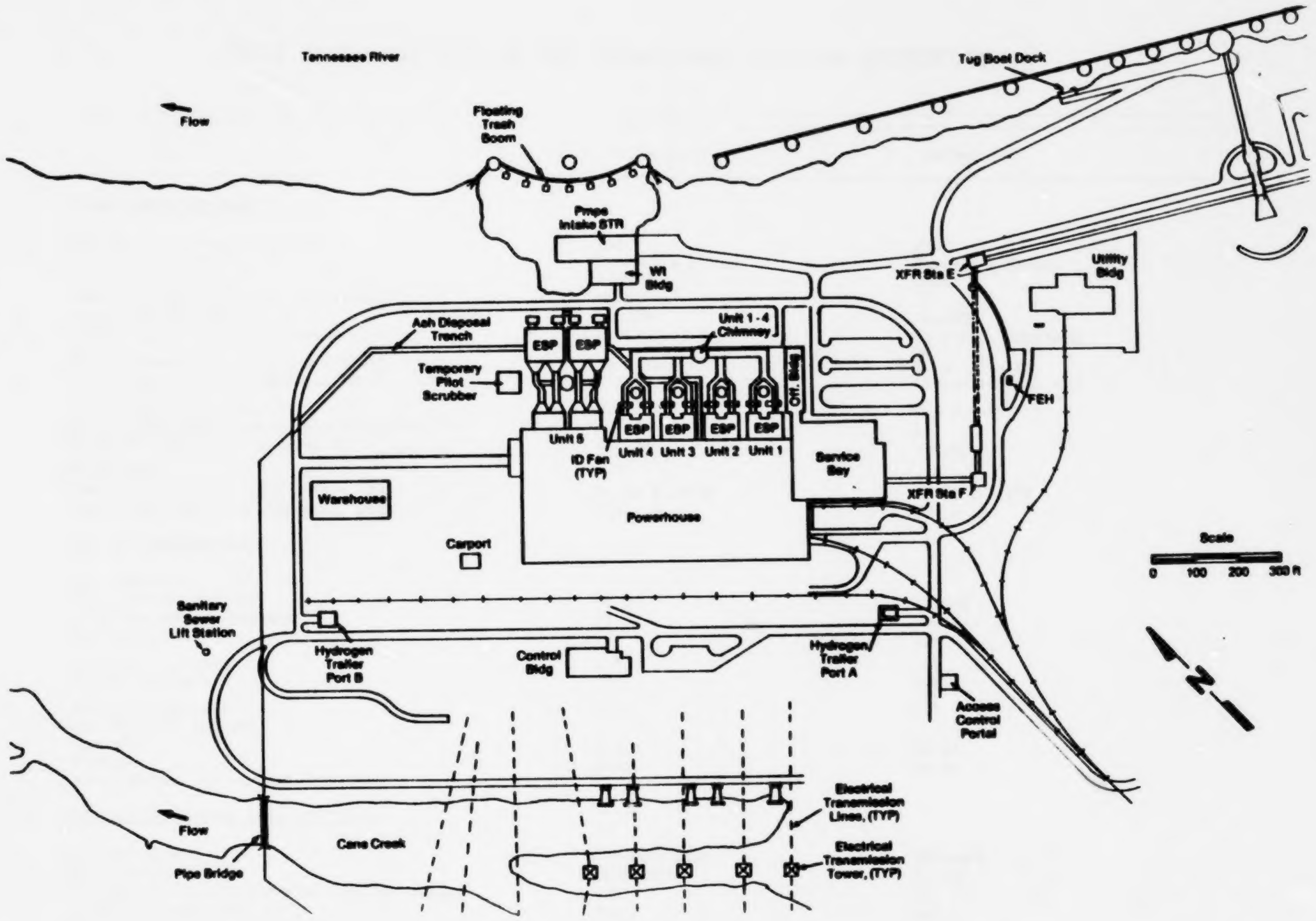

Figure 14-1. Colbert Plant plot plan.

TABLE 14-1. KEY DESIGN AND OPERATIONAL DATA FOR COLBERT PLANT

Item	Boilers 1-4	Boiler 5
BOILER AND STACK DATA		
Net generating capacity (MW)	194	496
Boiler manufacturer	Babcock & Wilcox	Babcock & Wilcox
Installation date	1955	1965
Capacity factor (10 year projected)	55-69	33
Heat rate (Btu/kW-hr)	10,000	10,482
Boiler type/firing type/bottom type	Wall-fired/dry	Wall-fired/opposed
Boiler dimensions, (ft, D x W x H^a)	23 x 38 x 47	32 x $--^b$ x 86
Burner type/number of burners (# EL x #/EL)	Circular/3x6	Circular (5x6) x 2
Burner spacing (vert x horiz, ft)	8.6 x$--^b$	8.6 x $--^b$
Burner zone heat release rate (Btu/hr-ft^2)	407	—
Design oxygen level (percent O_2)/excess air	3.5/20	3.5/20
Draft type	$--^b$	$--^b$
Flue gas flow rate (1000 acfm @ °F)	3,158 @ 295°F	2,009 @ 310°F
Stack size (height x diameter, feet)	634 x 26.2	500 x 21
FUEL AND SORBENT DATA		
Coal quality^c		
Heat content (Btu/lb)	11,600	11,600
Volatile matter (percent)	27.7	27.7
Ash (percent)	12	12
Moisture (percent)	$--^b$	$--^b$
Sulfur (percent)	2.3	2.3
Nitrogen (percent)	$--^b$	$--^b$
Coal delivery methods		
Current	Barge	Barge
Design	Barge	Barge
Likely method for sorbent delivery		
PARTICULATE CONTROL EQUIPMENT DATA		
Type of control	ESP/cold side	ESP/cold side
Installation date	1971-1972	Retrofit
ESP specific collection area ($ft^2/10^3$ acfm)	175	327
Total plate area (10^3 ft^2)	158.5	654.4
Emission standards (lb/10^6 Btu)	0.12	0.12
ESP outlet emissions (lb/10^6 Btu)^d	0.05	0.02
Design coal sulfur (percent)	3.5	1.5
Gas conditioning	None	None
Tested efficiency/design efficiency	99.6/97	99.3/99.5

(Continued)

TABLE 14-1. (CONTINUED)

Item	Boilers 1-4	Boiler 5
NITROGEN OXIDE CONTROL EQUIPMENT DATA		
NO_x control equipment	None	None
SULFUR DIOXIDE CONTROL EQUIPMENT DATA		
SO_2 control equipment	None	None
SOLID WASTE DISPOSAL DATA		
Ash transport system type		
Boiler bottom ash	Wet sluice	Wet sluice
Economizer bottom ash	Wet sluice	Wet sluice
ESP fly ash	Wet sluice	Wet sluice
Ash disposal method	Pond	Pond

[a] Furnace height from top of ash hopper to nose.

[b] Unknown value.

[c] Based on 1985 averages.

[d] Typical rate based on operating at the annual operating rate.

were designed for a coal sulfur content of 3.5 percent and a removal efficiency of 97 percent. The unit 5 ESP has a SCA of 327 $ft^2/10^3$ acfm; it was designed for a coal sulfur content of 1.5 percent and a removal efficiency of 99.5 percent. The actual particulate matter removal efficiency for units 1 through 4 is 99.4 percent, and for unit 5, 99.8 percent. The ESPs for units 1 through 4 emit 0.05 $lb/10^6$ Btu, and the unit 5 ESP emits 0.02 $lb/10^6$ Btu. Both are well below the current emission standard of 0.12 $lb/10^6$ Btu. Flue gas is routed to one 634-foot stack for units 1 through 4, and to a 500-foot stack for unit 5.

Ash from the boilers, economizers, and ESPs for all units are sluiced to one of the five ash sluice ponds located south and southwest of the plant. The fly ash disposal site has a remaining capacity of approximately 10 years. Plant personnel indicated that conversion from the wet sluice to a dry ash handling system is being considered.

14.2 COMMERCIAL SO_2 CONTROL TECHNOLOGIES

Commercial SO_2 control technologies evaluated at the Colbert plant include lime/limestone wet scrubbing (lime with and without MgO additive, limestone with and without organic acid additive), lime spray drying, coal switching and physical coal cleaning. The following sections present the retrofit issues and cost/performance estimates evaluated.

14.2.1 Lime/Limestone and Lime Spray Drying FGD

14.2.1.1 Control Cases Evaluated--

Table 14-2 lists the lime/limestone flue gas desulfurization (L/LS FGD) and lime spray drying (LSD FGD) SO_2 control cases evaluated. Retrofit costs and factors were developed for two basic SO_2 control configurations: (1) separate control systems for each unit, and (2) a low capital cost system which would have a shared control system for units 1-4 and a separate system for Unit 5. FGD control system components for unit 5 would not be shared with those for units 1-4, due to limited space available behind units 1-4.

TABLE 14-2. SUMMARY OF L/LS AND LSD FGD CASES EVALUATED FOR COLBERT PLANT

Case Description	SO_2 Removal (%)	Coal Sulfur (wt. %)	SO_2 Reduction (tons per year)
INDIVIDUAL CONTROLS			
L/LS FGD			
Boiler 1	90	2.4	17,300
Boiler 2	90	2.4	17,300
Boiler 3	90	2.4	17,300
Boiler 4	90	2.4	17,300
Boiler 5	90	2.4	44,200
LSD FGD (reuse ESP)			
Boiler 5	64	2.4	31,300
LSD FGD (new baghouse)			
Boiler 1	83	2.4	16,000
Boiler 2	83	2.4	16,000
Boiler 3	83	2.4	16,000
Boiler 4	83	2.4	16,000

For the LSD FGD systems on units 1 through 4, two cases are considered: (1) where the existing ESPs are reused to collect the fly ash and spray dried particles and (2) where a new baghouse is installed. Because the ESPs for units 1-4 are small (<200 SCA) only the baghouse case was evaluated. For the LSD FGD system on unit 5, only the ESP reuse case is considered for the following reasons: (1) the existing ESPs current performance achieves the current particulate emission standards and (2) it was estimated by IAPCS that no additional ESP plate area would be required to handle the increased loading due to spray drying.

Since plant personnel indicated that limestone sorbent is economically more attractive and TVA has had extensive experience in using limestone, it is used as the basis for the L/LS FGD conceptual design discussed in the next section. However, lime is used for LSD FGD, and lime FGD costs were developed. For L/LS FGD the following process option was examined: (1) forced oxidation to produce an easily dewatered gypsum waste for ponding and (2) conventional limestone FGD where the FGD waste is stabilized with dry fly ash from the ESPs. Both options assume on-site waste disposal.

SO_2 removal efficiency for L/LS FGD is assumed to be 90 percent. The estimated removal efficiency for LSD FGD with retrofit fabric filters at units 1-4 was 83 percent and 64 percent when the existing ESP is reused at unit 5. The lower SO_2 removal efficiency for unit 5 is due to a lower flue gas temperature and the decreased SO_2 removal that occurs within the ESP versus that of a baghouse.

14.2.1.2 Layout of Equipment and Design Basis--

An important consideration in the development of retrofit factors and costs is the placement of the major components of the SO_2 control system. Site-specific access/congestion and other factors can complicate the placement of the control equipment impacting retrofit cost. For each SO_2 control case considered, a simplified plot plan or conceptual design was prepared to illustrate the placement of the key components of each SO_2 control system. Absorbers, spray dryers, ductwork, baghouses, clarifiers/

vacuum filters, sorbent preparation, sorbent receiving and storage, and FGD waste storage systems are shown on each drawing.

The following is a list of the drawings developed to illustrate the SO_2 control cases.

Figure Number	SO_2 Control Case Description
14-2	Conventional LS FGD system for units 1 through 4 and a separate LS FGD system for unit 5.
14-3	Individual LSD FGD system for units 1 through 5.

These drawings are not intended to represent the accuracy and detail associated with an engineering drawing but are approximately to scale. They were prepared from drawings supplied by the plant, sketches and measurements made during the plant visit, and photographs taken during the plant visit. The layouts for the individual and combined system cases would be similar. The majority of the control equipment was located in open areas to the west of unit 5 and the east of units 1 through 4. The clarifiers/vacuum filters and waste stackout are all located to the west of the plant for units 1 through 5. If a limestone forced oxidation system were used, there would be no need for waste stack out near the boilers as is the case for the LSD layout.

14.2.1.3 Scope Adjustments--

In order to retrofit control systems at the Colbert plant, some existing equipment must be modified and costs not included in the IAPCS models must be added to account for these modifications. These are referred to as scope adjustments or cost adders and are summarized in table 14-3 for all FGD cases evaluated.

The cost of converting the ESPs ash removal and conveyance system from a wet to a dry system is included. Dry waste is assumed to be necessary for conventional L/LS FGD sludge stabilization but not for the forced oxidation FGD. For the new baghouse LSD cases, IAPCS adds the cost of the baghouse as a separate line item.

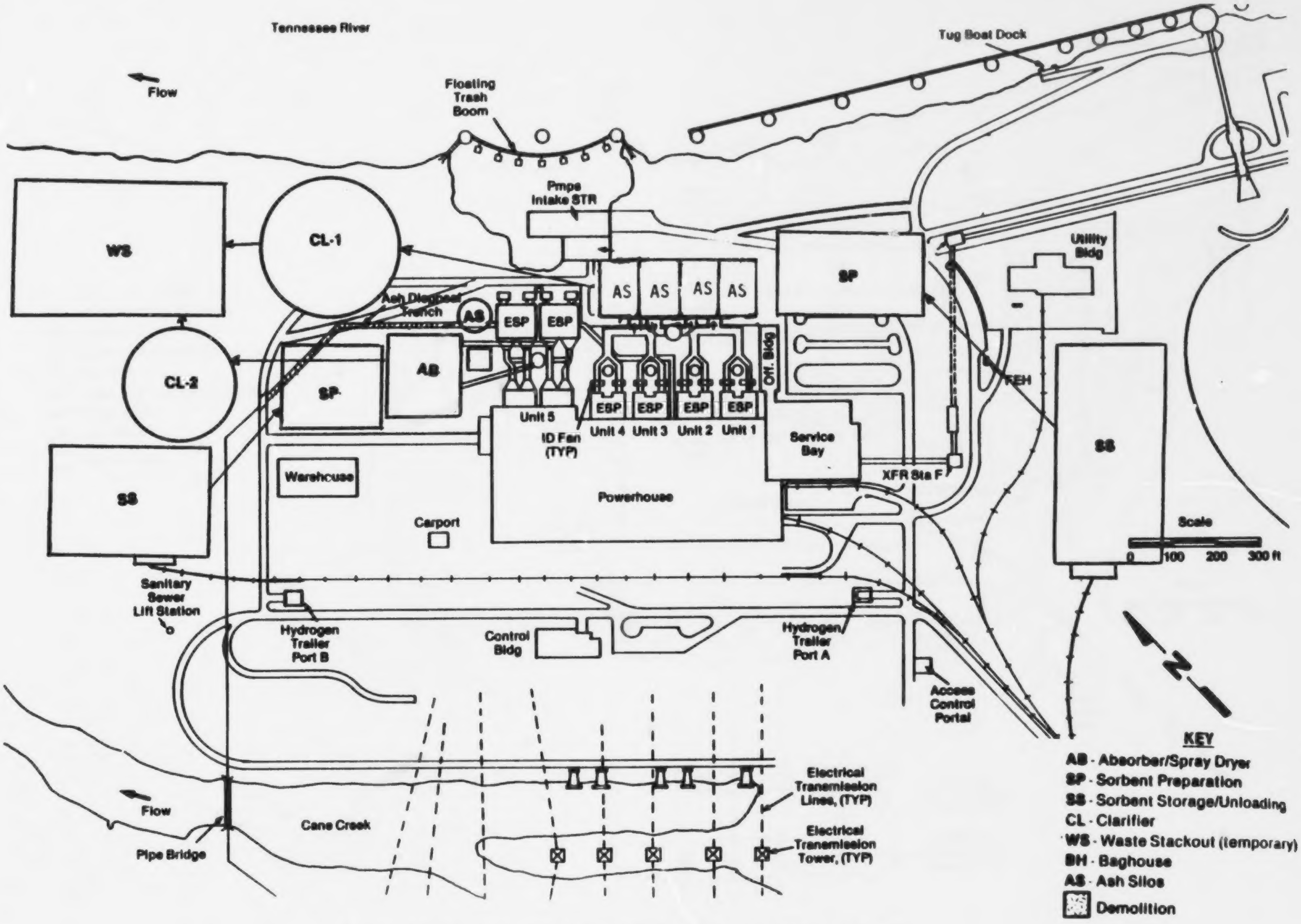

Figure 14-2. Colbert Plant limestone FGD systems.

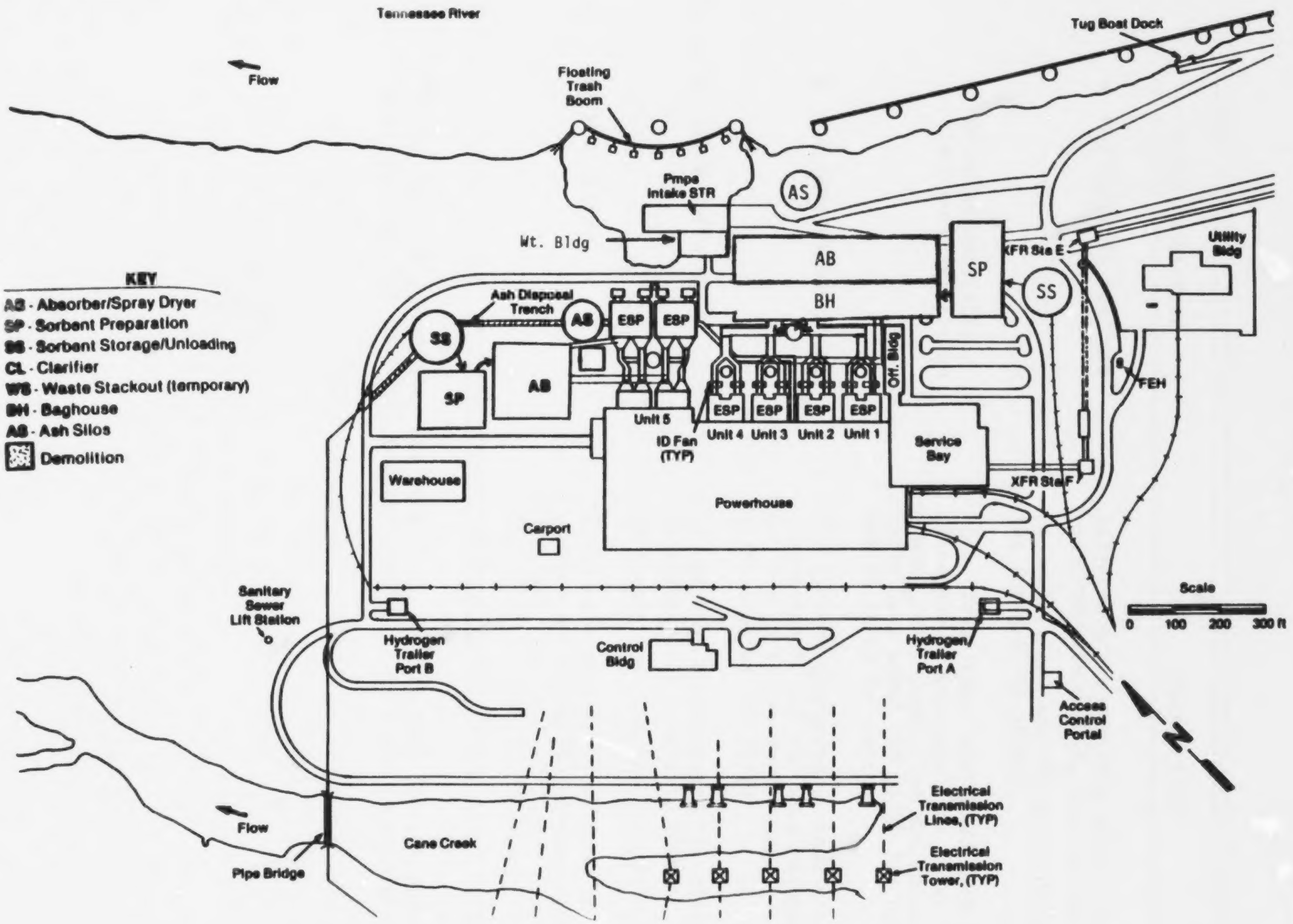

Figure 14-3. Colbert Plant lime spray drying FGD systems.

TABLE 14-3. SCOPE ADJUSTMENTS INCLUDED IN FGD RETROFIT FOR COLBERT PLANT

Scope Adjustment	Description[a]
• Modify draft controls	Balanced draft controls would likely be required with new SO_2 control systems to prevent large negative pressure surges in the furnace ($1.20/kW).
• Building demolition, duct work demolition	When these items interfered with the placement of equipment (as shown in figure 14-2) demolition and relocation costs were added ($0.23/kW for units 1-4 and $0.18/kW for unit 5).
• Ash removal/conveyance	The ESP ash discharge systems for conventional L/LS FGD were changed from wet sluice to dry for sludge stabilization ($7.28/kW).
• Stack relining	It was assumed necessary to reline existing steel stacks to prevent corrosion for L/LS FGD ($40/ft^2).
• New rails	A new rail spur was installed to allow sorbent unloading operations to be separate from coal unloading operations for all FGD cases ($189,000).

[a] Costs shown in parentheses are base costs in June 1985 dollars and have not been adjusted for location, process, retrofit, or other considerations.

A new rail spur would be installed to allow sorbent unloading operations to be separated from coal unloading operations. An estimated 1,000 feet of new rail lines would be needed for sorbent unloading operations at a cost of 1 x 10^6 dollars per mile (ConRail, 1986).

The costs for balanced draft controls, duct demolition, and for stack relining were based on EPRI guidelines. Costs to relocate plant roads was accounted for in the general facilities cost. For all cases a general facilities factor of 10 percent was used for all units.

14.2.1.4 Location and Retrofit Factors--

Tables 14-4 thru 14-5 present the location and retrofit factors used for L/LS and LSD FGD. The aggregate location factor presented in the column titled LOCF incorporates the following factors: seismic zone factor of 2.0, climate zone factor of 0.99, (no insulated siding needed) and labor productivity and materials factor of 0.94 (Alabama). The soil factors reflect riverside conditions, where control costs would be higher than the EPRI base case.

Table 14-6 presents the tie-in distances between process areas used. Tie-in ductwork length has a significant impact on the flue gas handling retrofit factor for long tie-in ductwork distances greater than 500 feet. The distance from waste processing and sorbent preparation to the absorbers is a minor cost consideration for L/LS FGD and LSD FGD.

Retrofit factors generally were higher for units 1-4 than for unit 5, because most FGD control system components at unit 5 have relatively free access with little congestion. Low access/congestion retrofit factors were used for unit 5 to adjust the flue gas handling absorber and particulate collector costs. Units 1-4 have low to medium access/congestion factors with the medium factors due to the somewhat limited space available between the chimney and river. The underground obstruction factor adjusts the base cost for subsurface interferences. Low to medium underground obstruction factors were used for units 1 through 5, as several underground obstructions would be

TABLE 14-4. RETROFIT FACTOR SUMMARY FOR L/LS FGD CASES EVALUATED FOR COLBERT PLANT

		RETROFIT FACTORS							
	All Units	Boiler #1-4				Boiler #5			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.00	1.06	1.15	1.00	1.22	1.01	1.05	1.00	1.06
SO_2 Removal	0.95	1.03	1.30	1.00	1.34	1.03	1.10	1.00	1.13
Flue Gas Handling	1.01	1.03	1.30	1.10	1.47	1.03	1.10	1.30	1.47
Waste Handling	0.99	1.03	1.05	1.04	1.12	1.03	1.05	1.02	1.10
General Support Equipment	1.00	1.06	1.24	1.00	1.31	1.06	1.08	1.00	1.14
SCOPE ADJUSTMENTS									
Wet to Dry Ash System	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
New Rail Spur	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Chimney	0.99	1.00	1.10	1.00	1.10	1.00	1.10	1.00	1.10
Demolition	0.94	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	0.94	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			11				11		
General Facilities - %			10				10		

[a] LOCF = Location Factor.

[b] UGOF = Underground Obstruction Factor.

[c] ACCF = Access Congestion Factor.

[d] DISF = Distance Factor. See table 14-6 for distance assumptions.

[e] AGGF = Aggregate Factor.

TABLE 14-5. RETROFIT FACTOR SUMMARY FOR LSD FGD CASES EVALUATED FOR COLBERT PLANT

	RETROFIT FACTORS								
	All Units	Boiler #1-4				Boiler #5			
Item	LOCF[a]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]	UGOF[b]	ACCF[c]	DISF[d]	AGGF[e]
PROCESS EQUIPMENT									
Reagent Feed	1.17	1.06	1.15	1.00	1.22	1.01	1.05	1.00	1.06
SO_2 Removal	1.02	1.03	1.30	1.00	1.34	1.03	1.10	1.00	1.13
Flue Gas Handling[f]	1.14	1.03	1.30	1.35	1.81	1.03	1.10	1.25	1.42
General Support Equipment	1.15	1.06	1.24	1.00	1.31	1.06	1.08	1.00	1.14
SCOPE ADJUSTMENTS									
Wet to Dry Ash System[g]	N/A[h]	N/A	N/A	N/A	N/A	1.00	1.00	1.00	1.00
New Rail Spur	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Chimney	0.95	1.03	1.10	1.00	1.13	N/A	N/A	1.00	N/A
ESP Upgrade	N/A	N/A	N/A	N/A	N/A	1.01	1.10	1.00	1.11
New Baghouse	1.02	1.03	1.10	1.00	1.13	N/A	N/A	N/A	N/A
Demolition	0.94	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Draft Controls	0.95	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ADDITIONAL INDIRECT FEES									
Engineering - %			11				11		
General Facilities - %			10				10		

[a] LOCF = Location Factor.
[b] UGOF = Underground Obstruction Factor.
[c] ACCF = Access Congestion Factor.
[d] DISF = Distance Factor. See table 14-6 for distance assumptions used.
[e] AGGF = Aggregate Factor.
[f] Flue gas handling aggregate factor includes ductwork tie-in costs.
[g] This change is not necessary for cases where a new baghouse is installed.
[h] N/A = Not applicable.

TABLE 14-6. KEY DISTANCES USED IN DEVELOPING FGD RETROFIT FACTORS FOR COLBERT PLANT

FGD Case	Duct Tie-In Distances (feet) Inlet[a]	Duct Tie-In Distances (feet) Outlet[b]	Sorbent Prep to Absorber (feet)	Absorber to Waste Treatment (feet)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	200	50	100	600
Boiler 2	200	50	100	600
Boiler 3	200	50	100	600
Boiler 4	200	50	100	600
Boiler 5	250	200	100	350
LSD FGD (new baghouse)				
Boiler 1	400	100	100	N/A[c]
Boiler 2	400	100	100	N/A
Boiler 3	400	100	100	N/A
Boiler 4	400	100	100	N/A
LSD FGD (reuse ESP)				
Boiler 5	250	150	100	N/A
LOW COST CONTROLS				
L/LS FGD				
Boilers 1-4	200	50	100	600
Boiler 5	200	200	100	350

[a] New duct work needed to tie-in the existing ductwork to the FGD absorber inlet.

[b] New duct work needed to tie-in the FGD absorber outlet to the stack.

[c] N/A = Not applicable for spray drying FGD.

encountered in the vicinity of units 1 through 5 (e.g., the ash disposal trench, the intake water and circulating water pipes).

14.2.1.5 Overall Retrofit Factors and Costs--

Table 14-7 presents the overall retrofit factors and costs for all FGD cases evaluated at the Colbert plant. The range of costs shown for L/LS FGD reflect the different process options examined: limestone FGD with adipic acid and lime with MgO additive, conventional lime/limestone FGD and limestone FGD with forced oxidation. The EPRI overall retrofit factor is determined by dividing the EPRI retrofit capital cost by the EPRI base capital cost (after adjusting for process factors as described above).

LSD FGD retrofit factors developed for IAPCS cost calculations do include the impact due to the addition of a new baghouse. However, since IAPCS adds the baghouse cost as a separate lime item, a separate baghouse retrofit factor is input to IAPCS for estimating particulate control costs.

Figures 14-4 and 14-5 summarize the plant level costs of installing L/LS and LSD FGD. For L/LS FGD, only the costs for lime FGD were plotted. Application of L/LS FGD is estimated to reduce plant-wide SO_2 emissions by 113,400 tons per year assuming 90 percent emission reduction. The low capital cost LS FGD case reduces capital costs by 50 percent for units 1-4 and by 35 percent for unit 5. For application of LSD FGD, the estimated emission reduction is 95,300 tons per year with reuse of unit 5 ESPs and with replacement fabric filters on units 1 through 4.

14.2.2 Coal Switching/Blending

Presented in table 14-8 are the coal analyses for the coal used at Colbert in 1985 and the alternative coal used to evaluate coal switching. The switch coal is low sulfur Kentucky coal having a sulfur content of 0.98 percent.

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer

TABLE 14-7. L/LS AND LSD FGD COSTS FOR COLBERT PLANT (August 1987 Dollars)

Case Description	Overall Retrofit Factor	IAPCS Retrofit Costs[a] Capital Cost ($/kW)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
INDIVIDUAL CONTROL SYSTEMS				
L/LS FGD				
Boiler 1	1.54	283.1-334	1,222-1,383	22.2-25.1
Boiler 2	1.54	283.1-334	1,222-1,383	22.2-25.1
Boiler 3	1.54	283.1-334	1,222-1,383	22.2-25.1
Boiler 4	1.54	283.1-334	1,222-1,383	22.2-25.1
Boiler 5	1.38	179.5-214.7	807-938	14.7-17.1
LSD FGD (reuse ESP)				
Boiler 5	1.30[b]	139.0	784	10.1
LSD FGD (new baghouse)				
Boiler 1	1.80[c]	288.7	1,171	19.7
Boiler 2	1.80[c]	288.7	1,171	19.7
Boiler 3	1.80[c]	288.7	1,171	19.7
Boiler 4	1.80[c]	288.7	1,171	19.7
LOW COST CONTROL SYSTEMS				
L/LS FGD				
Boilers 1-4[a]	1.54	143.1	585	10.6
Boiler 5	1.38	131.2	574	10.4

[a] The range in costs shown for L/LS FGD represents the different process options evaluated: limestone slurry FGD, lime slurry FGD, limestone slurry with adipic acid enhancement, and lime slurry with MgO addition. The limestone slurry technology is generally at the high end of the range while the adipic acid and MgO enhanced technologies are at the low end.

[b] No plate area increase needed.

[c] Includes impact of new baghouse.

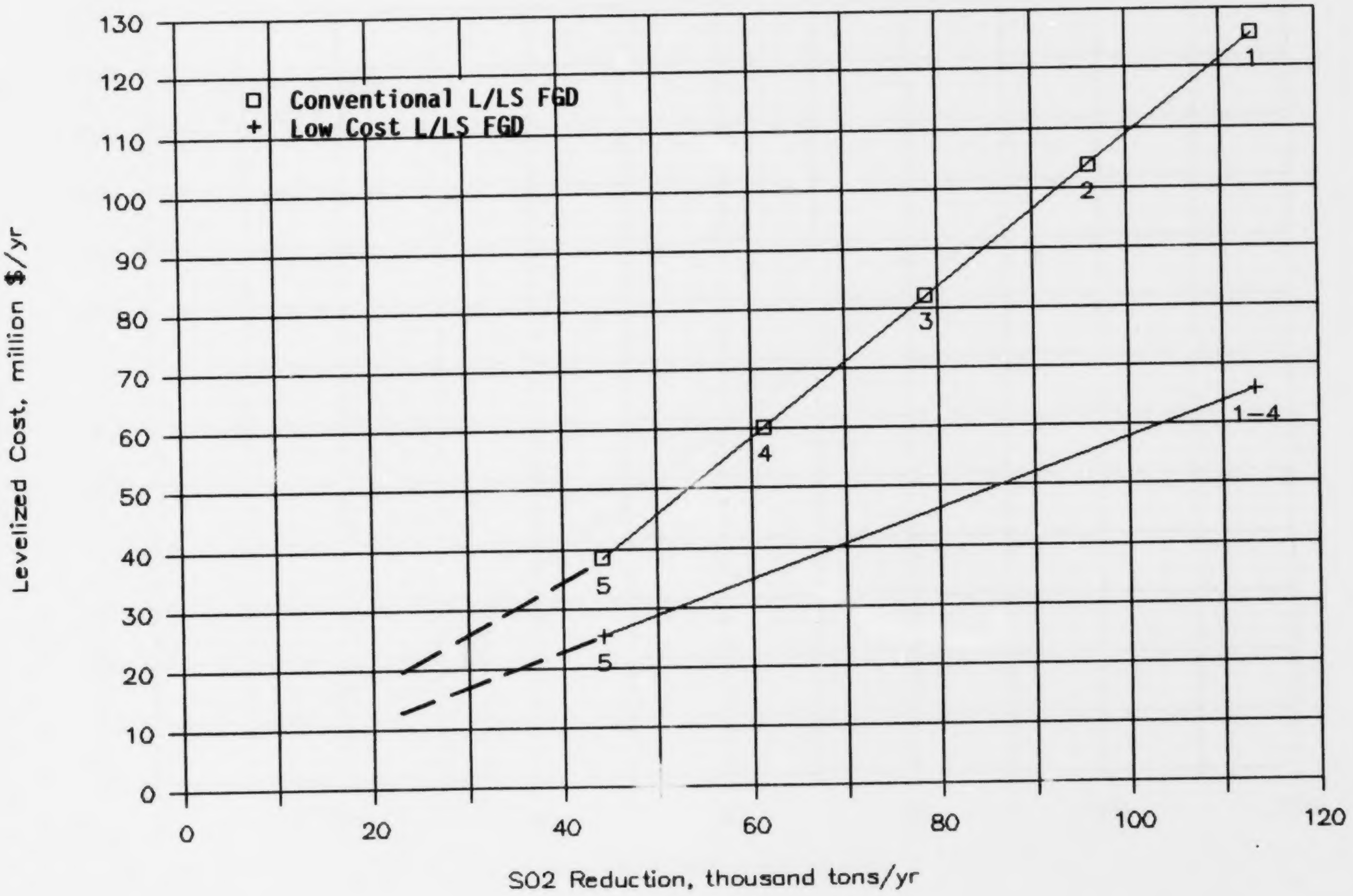

Figure 14-4. Colbert Plant L/LS cost versus SO_2 reduction.

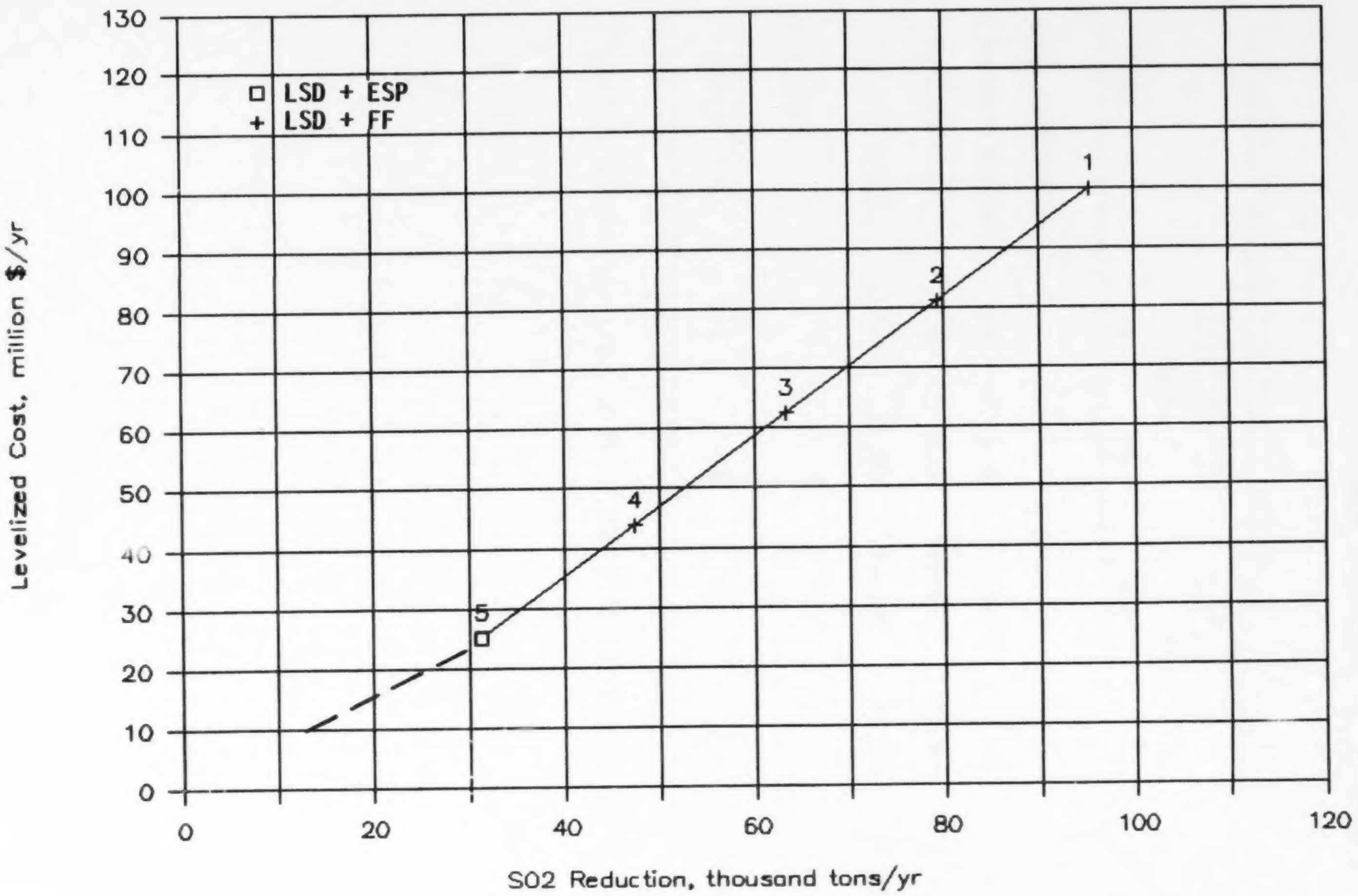

Figure 14-5. Colbert Plant lime spray dryer FGD cost versus SO_2 reduction.

TABLE 14-8. CHARACTERISTICS OF EXISTING, SWITCH, AND CLEANED COALS FOR COLBERT PLANT

	Existing Coal		Switch Coal		Cleaned Coal	
	Boiler		Boiler		Boiler	
Item	1-4	5	1-4	5	1-4	5
COAL PARAMETERS						
Percent sulfur	2.4	2.4	0.98	0.98	1.9	1.9
Percent ash	11.6	11.6	10.50	10.50	5.89	5.89
Btu per pound	11,564	11,564	12,100	12,100	12,459	12,459
ESP SCA[a]						
Existing/ needed SCA[a]	175	372	213	213	213	213

[a] Specific collection area in ft^2/1,000 acfm after SO_3 conditioning.

capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. However, because the benefits of SO_3 conditioning are highly variable, the predicted ESP plate area increase should be viewed as a minimum estimate. For boiler 5 no additional plate area would be required.

Figure 14-6 presents the plant level cost and emission reduction for switching to a low-sulfur coal. Curves were generated to show the impact of different coal fuel price differentials. The lower curve represents a 1985 fuel price differential of $1.71 per ton between the existing coal and an eastern Kentucky low sulfur coal. The upper curve shows the impact of additional fuel price differential of $15 per ton over the 1985 fuel price differential. Approximately 77,300 tons per year of SO_2 reduction would be achieved by switching to a coal having a 1.6 pound SO_2 per million Btu emission rate. The costs associated with each boiler for the range of fuel cost differential (FCD) are shown in table 14-9.

TABLE 14-9. COAL SWITCHING COSTS FOR COLBERT PLANT
(August 1987 Dollars)

		@ $1.71/ton FCD		@ $16.71/ton FCD	
Boiler	SO_2 Reduction (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1	11,800	182	2.2	693	8.6
2	11,800	182	2.2	693	8.6
3	11,800	182	2.2	693	8.6
4	11,800	182	2.2	693	8.6
5	30,100	146	1.8	657	8.1

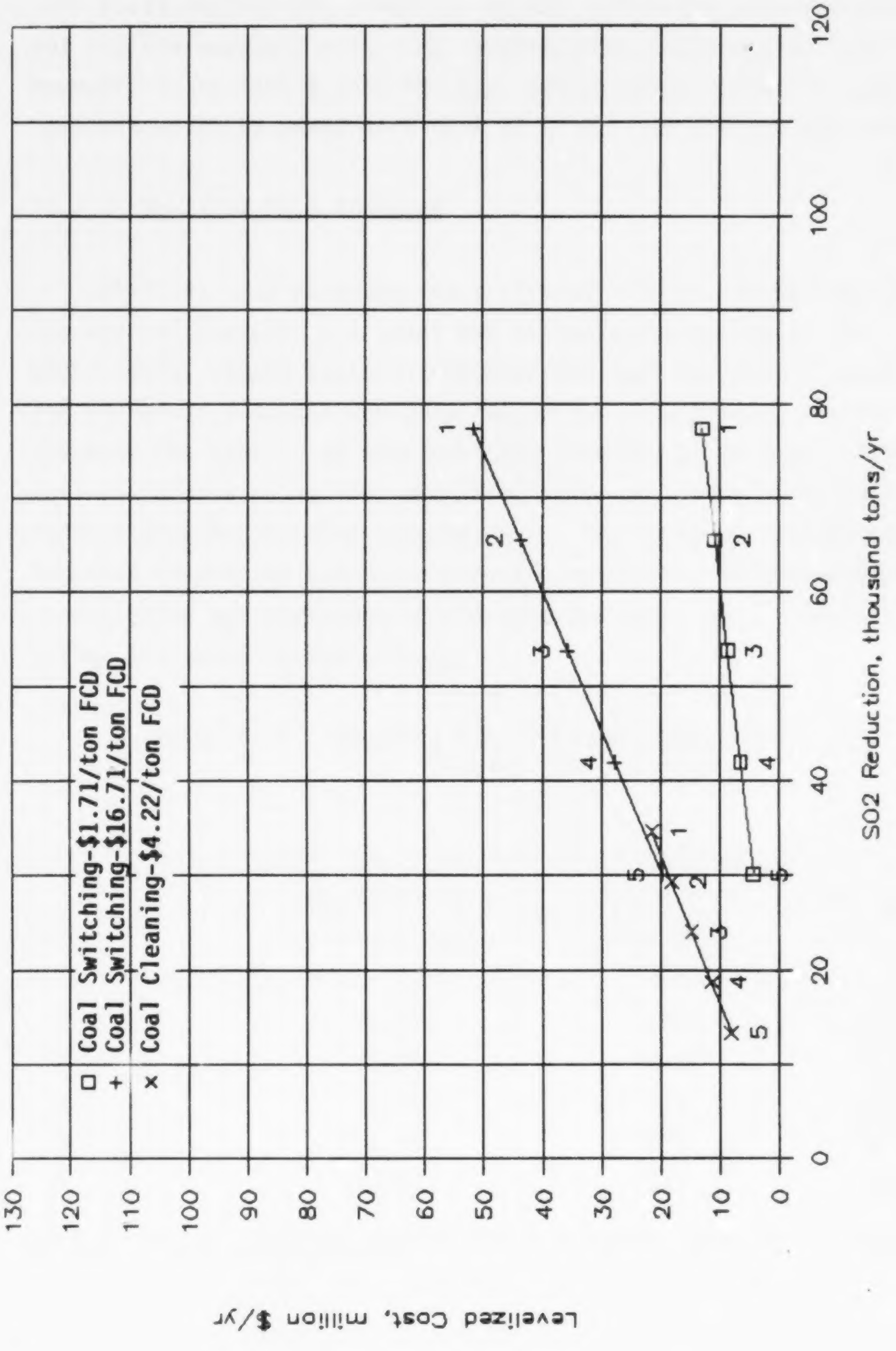

Figure 14-6. Colbert Plant coal switching/cleaning costs versus SO_2 reduction.

Costs include SO_3 conditioning and additional area for units 1-4 but do not include new coal receiving, segregation, and blending facilities. However, it is likely that for coal switching at units 1-4, new particulate controls would be added at a cost of 14 million dollars per unit.

14.2.3 Physical Coal Cleaning

Physical coal cleaning was evaluated using a similar medium sulfur coal. The cost of cleaning this coal was estimated using one of the standard IAPCS model coals. IAPCS costs assume that the coal would be cleaned at the mine and no refuse disposal would be required at the plant. Figure 14-6 also presents the results of physical coal cleaning at Colbert. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal. The costs do include the estimated increase in coal cost for the cleaning operation ($4.22 per ton) and SO_3 conditioning and additional plate area for units 1-4. Cost estimates for each boiler are shown in table 14-10.

TABLE 14-10. PHYSICAL COAL CLEANING COSTS FOR COLBERT PLANT
(August 1987 Dollars)

Boiler	SO_2 Reductions (tons per year)	Unit Cost ($/ton SO_2)	Levelized Cost (mills/kWh)
1	5,300	676	3.7
2	5,300	676	3.7
3	5,300	676	3.7
4	5,300	676	3.7
5	13,400	595	3.3

14.3 DEVELOPING SO_2 CONTROL TECHNOLOGIES

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data. For the Colbert plant the following control technologies were considered: furnace sorbent injection (FSI), duct spray drying (DSD) and retrofit applicability of fluidized bed combustion (FBC) or coal gasification (CG). The following discussion presents the retrofit issues and cost/performance estimates developed.

14.3.1 Sorbent Injection Technologies

FSI and DSD are being developed specifically for retrofit situations. As such, many retrofit costs are built into the base case design and costs. The retrofit factors developed for these technologies focus on developing scope adders which are not included in the base capital cost assumptions. These include demolition and relocation of existing equipment/buildings and ESP upgrade costs. Basic assumptions and cost adjustments made for FSI and DSD are presented in table 14-11. The following section discusses the retrofit factor basis for each technology separately.

14.3.1.1 Furnace Sorbent Injection--

FSI retrofit factors were developed for boiler unit 5 only because the ESPs for units 1-4 are too small to be sufficiently upgraded. Pulverized calcium-based sorbent would be injected directly into the upper furnace cavity. The equipment layout is similar to the duct spray drying layout except that furnace injectors rather than duct injectors would be used. Also, day bins would be located close to the unit and a sorbent slurry area would not be necessary.

TABLE 14-11. SCOPE ADJUSTMENTS FOR FSI AND DSD AT COLBERT PLANT

	Boiler	
Item	1-4	5
BASIC ASSUMPTIONS		
Approximate access/congestion rank	Low-medium	Low
Is new particulate collector case evaluated?	Yes	No[a]
Distance to final waste disposal (miles)	<1	<1
SCOPE ADDERS		
Upgrade the existing particulate collector ash removal system (install a dry system)	No	Yes
New railroad spur (ft)	Yes	Yes
Additional duct work (ft)[b]	150	100
Duct demolition length (ft)[b]	50	50
ADDER COSTS AND RETROFIT FACTOR SUMMARY		
Scope adder cost for DSD[a] with new baghouse (10^3 $)[c]	1,350 (each)	N/A[c]
Scope adder costs for DSD and FSI with reuse ESP 10^3 $)[c]	N/A[d]	3,920
Baghouse retrofit difficulty factor	1.33	N/A[c]
ESP upgrade retrofit difficulty factor (for plate area addition)	N/A[e]	1.11

[a] A new baghouse is not necessary.

[b] For a new baghouse case only.

[c] June 1985 dollars.

[d] Not applicable because reuse of ESP was evaluated for FSI and DSD.

[e] Not applicable for reuse; only DSD with new baghouse considered.

14.3.1.2 Duct Spray Drying--

Duct spray drying using a lime slurry sorbent was evaluated for all units. Lime received by new rail facilities would be stored in sorbent storage silos. Sorbent receiving, storage and preparation areas for units 1 through 4 would be located to the east of the plant, while for unit 5 these facilities would be located to the west of the plant.

Duct spray drying would be accomplished by injecting lime slurry in the ductwork upstream of a particulate control device. The concept is the same as conventional spray drying, the difference being that the residence time in the duct is much shorter (1 to 2 seconds) compared to a spray drying chamber (10 to 12 seconds). Since reusing the existing ESPs on units 1-4 could be problematic, a new fabric filter system case was evaluated. IAPCS estimates that the unit 5 ESP is adequate, and a new baghouse case would not be necessary.

The sorbent would be injected into the units 1 through 4 ductwork at a point 150 ft from the entrance to the baghouse. The sorbent would be injected into the unit 5 ductwork in or near the old ESPs which are 100 ft from the entrance to the ESP.

14.3.1.3 Overall Retrofit Factors and Costs--

Table 14-12 presents the estimated retrofit costs for FSI and DSD. Figure 14-7 presents the cost of retrofitting FSI and DSD on boilers 1-5 versus plant level SO_2 reductions achieved.

Two curves are presented to span the range of anticipated SO_2 removal (50 and 70 percent) and sorbent utlization (25 and 35 percent) for FSI at unit 5. SO_2 emissions are reduced by 24,600 tons per year under the 50 percent removal case and by 34,400 tons per year under the 70 percent removal case. Plant-wide SO_2 emissions for DSD are reduced by 73,600 tons per year.

TABLE 14-12. RETROFIT COSTS FOR FSI AND DSD FOR COLBERT PLANT (August 1987 Dollars)

Case Description	IAPCS Capital Cost ($/kW)	IAPCS Levelized Cost (mills/kWh)	IAPCS Unit Cost ($/ton SO_2)	SO_2 Reduction (tons/yr)
Furnace Injection (50 % removal)[a]				
Boiler 5	58.9	7.9	785	24,600
Furnace Injection (70 % removal)[b]				
Boiler 5	60.0	8.0	567	34,400
Duct Spray Drying (reuse ESP)				
Boiler 5	55.3	5.9	706	20,500
Duct Spray Drying (new baghouse)				
Boilers 1-4	116.8	8.2	585	53,100

[a] This case presented corresponds to 25 percent sorbent utilization in the furnace and 50 percent SO_2 removal.

[b] This case corresponds to 35 percent sorbent utilization in the furnace and 70 percent SO_2 removal.

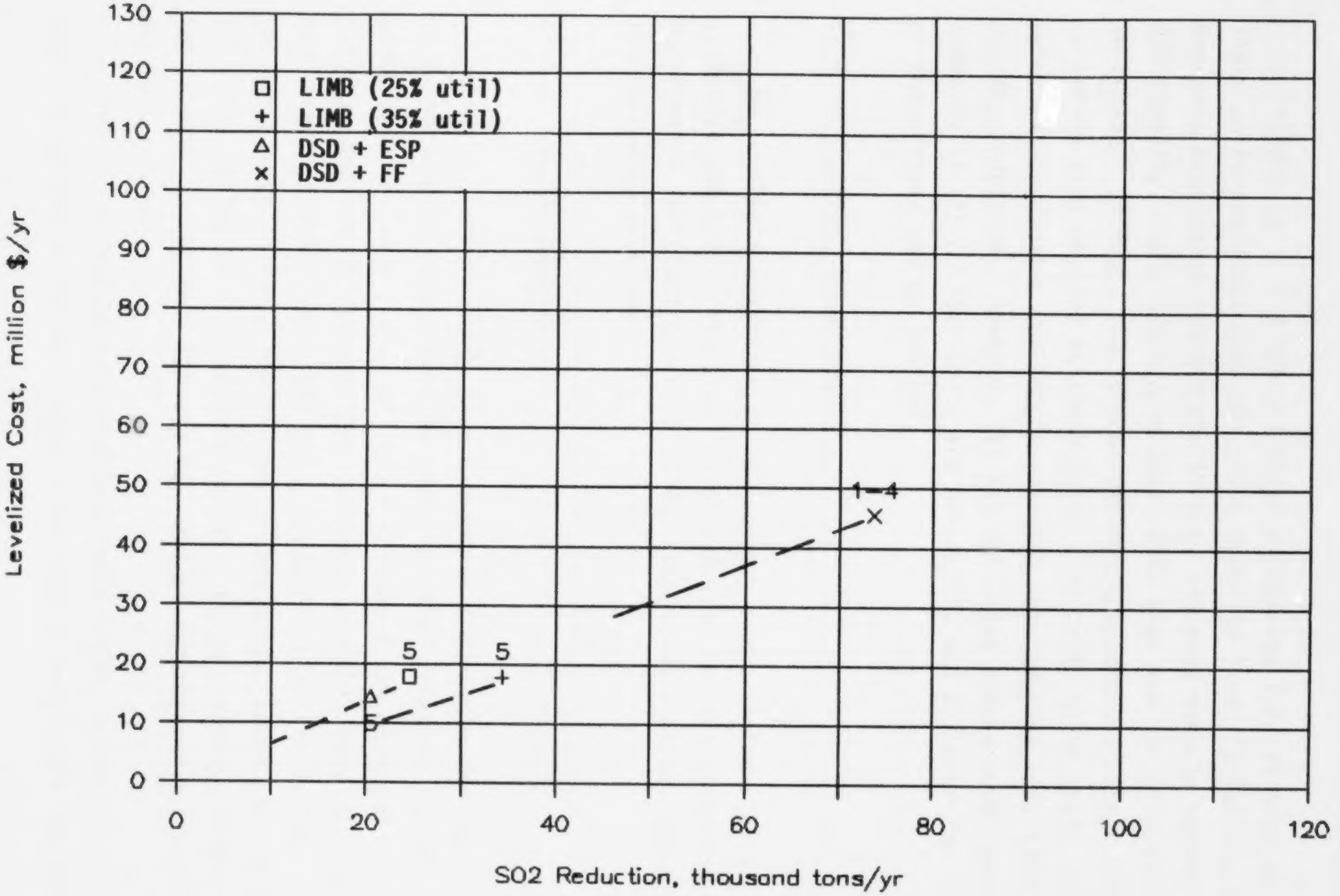

Figure 14-7. Colbert Plant FSI/DSD cost versus SO_2 reduction.

14.3.2 Fluidized Bed Combustion (FBC) and Coal Gasification (CG) Retrofit

Colbert units 1-4 are potential candidates for retrofit of FBC and CG. These units are small (200 MW), have moderate capacity factors (56 %) and moderate heat rates (10,000 Btu/kW-hr), and have been in service 32 years. Additionally, these units have small ESPs that are not acceptable for coal switching. In fact, TVA is considering replacement of these ESPs if coal switching were applied at these units. As such, these units are good potential candidates for FBC/CG retrofit for combined life extension and SO_x/NO_x reduction. However, TVA has extensive excess power generating capacity if its nuclear units are available, and the need for life extension of these units may be limited.

14.4 NO_x CONTROL TECHNOLOGIES

NO_x controls evaluated at the Colbert plant include low NO_x burners and selective catalytic reduction. Site-specific factors affecting the performance and costs of retrofit NO_x combustion controls are discussed in the following sections.

14.4.1 Low NO_x Burners

Low NO_x burners (LNB) were considered applicable for the Colbert units. Site specific factors affecting performance of retrofit low NO_x controls are summarized in Table 14-1. Boilers 1 through 4 are equipped with circular burners, and low NO_x burners are available for this type of unit. The burner heat input (approximately 100 million Btu/hr) relative to the furnace depth (approximately 23 feet) and to the furnace height above the top burner row (22 feet) is low to intermediate for wall-fired circular burners. Flame impingement on the rear furnace wall and/or superheater tube surfaces would not be a problem.

However, carbon burnout problems could occur, as the nonvolatile fraction of the boiler heat input flux (approximately 318 Btu/sec^2-ft^2)

relative to the bulk furnace residence time (0.9 seconds) and the upper furnace residence time (0.4 seconds) is excessively high. For thermal NO_x effects, the volumetric heat release rate (approximately 43,000 $Btu/hr-ft^3$) is excessively high for a front wall-fired unit. The burner zone heat release rate (approximately 280,000 $Btu/hr-ft^2$) is high for a front wall-fired unit. For fuel NO_x effects, the vertical burner spacing (approximately 8.6 feet) is relatively tight for these intermediate size burners and could result in more flame interaction, diminishing LNB NO_x reduction performance. Based on these considerations, it appears that the furnaces in Colbert boilers 1 through 4 are generally compact and would tend to lower the NO_x reduction performance of a LNB retrofit.

No coal slagging problems were identified at Colbert units 1 through 4, although the excess air operating level (20 percent) is low to intermediate. If the coal has a low slagging tendency, there may be additional excess air margin for LNB operation, promoting greater NO_x reductions.

Based on these considerations, the NO_x reduction performance of a LNB retrofit at Colbert 1-4 is estimated to be intermediate (30 percent). This is due primarily to the relatively small furnaces and low excess air operating level (to avoid slagging) of Colbert boilers 1 through 4.

Boiler 5, equipped with circular burners, is an opposed wall-fired furnace design. The burner heat input (83 million Btu/hr) relative to the furnace depth (32 feet) and to the furnace height above the top burner row (42 feet) is low. Thus, flame impingement on the rear furnace wall and superheater tube surfaces would not limit the NO_x reduction performance of a LNB retrofit. In addition, the burner heat input relative to the vertical burner spacing (8.6 feet) is low for circular burners, so flame interaction between burner rows should be minimal, and not significantly impact LNB NO_x reduction performance.

No data on horizontal burner spacing were available to evaluate flame interactions between adjacent burners at the same elevation. Also, furnace width measurements were also not obtained. This prevents the evaluation of furnace volume and burner zone heat release rates, respectively, and the furnace residence time effects on NO_x reduction performance.

The plant indicated no slagging problems on boiler 5, although the excess air levels (approximately 20 percent) are low to intermediate. The medium sulfur coal (2.3 percent) burned at the Colbert plant could present some corrosion problems in addition to any increased slagging that could occur due to the reducing atmospheres and increased furnace exit gas temperatures commonly associated with LNB. It is expected that essentially no loss of NO_x reductions or boiler derating would occur.

Based on the current lack of slagging problems, relatively wide burner spacing, and low furnace depth and height, LNB retrofit at the Colbert plant boiler 5 is expected to exhibit high NO_x reduction performance of 50 percent.

14.4.2 Selective Catalytic Reduction

The major equipment items required for a selective catalytic reduction (SCR) system are the catalyst and catalytic reactor, controls, and equipment for receiving, storage, preparation, flow rate control, and injection of ammonia (NH_3) into the flue gas. Catalyst operating temperature requirements of 650-700^oF for coal-fired systems require the SCR system location to bypass part of the economizer or use a tail-end system with flue gas preheat.

For units 1-5, it was assumed that the tail-end SCR system would be used to minimize unit down times. Boiler 1-5 flue gases would be diverted after passing through the ESPs to the preheater and through the catalyst. Hot flue gas from the reactor would be cooled before returning to the chimney. The catalytic reactors would be located behind each unit and the chimney for units 1-4 and beside the ESP chimney to the northeast for unit 5.

Table 14-13 summarizes the SCR unit retrofit difficulty and scope adjustments for boiler units 1-5. The retrofit factor includes access and congestion and underground obstruction considerations. A moderate retrofit factor was applied to the SCR costs at unit 4 because of access and congestion considerations caused by the unit 5 ESPs. The areas behind units 1-3 and beside unit 5 are less congested, and low difficulty factors were assigned. However, if an FGD system is also installed, all SCR retrofit difficulty factors would be high.

TABLE 14-13. SCR RETROFIT DIFFICULTY AND SCOPE ADJUSTMENTS FOR COLBERT PLANT (August 1987 Dollars)

	Boiler				
Item	1	2	3	4	5
Site access and congestion for SCR reactor	Low	Low	Low	Medium	Low
SCOPE ADDER PARAMETERS					
Building demolition (1,000$)	0	0	0	0	0
Ductwork demolition (1,000$)	50	50	50	50	97
New duct length (feet)	250	250	250	250	450
New duct costs (1,000$)	1,858	1,858	1,858	1,858	6,045
New heat exchanger (1,000$)	2,825	2,825	2,825	2,825	5,184
Total scope adder costs (1,000$)	4,733	4,733	4,733	4,733	11,325
Retrofit factor for SCR	1.16	1.16	1.16	1.34	1.16
General facilities (percent)	17	17	17	17	13

14.4.3 Summary of NO_x Control Costs

Tables 14-14 and figure 14-8 present the annual cost of NO_x controls using LNB. It is estimated that 10,500 tons per year of NO_x reductions would be achieved by applying LNBs at an estimated unit cost of \$150 to \$438 per ton of NO_x removed. Application of SCR at units 1-5 would reduce NO_x emissions by \$22,800 tons per year at a unit cost of \$4,004 to \$4,864 per ton of NO_x removed.

TABLE 14-14. NO_X CONTROLS COSTS FOR COLBERT PLANT
(August 1987 Dollars)

NO_X Control	Boiler Number	NO_X Reduction (%)	Capital Cost ($/kW)	Unit Cost ($/ton NO_X)	Annual Cost (mills/kWh)	NO_X Reduced (tons/year)
Low NO_x Burner	1	30	14.5	438	0.6	1,300
	2	30	14.5	438	0.6	1,300
	3	30	14.5	438	0.6	1,300
	4	30	14.5	438	0.6	1,300
	5	50	8.3	150	0.3	5,500
Selective Catalytic Reduction	1	80	160.4	4,728	17.1	3,500
	2	80	160.4	4,728	17.1	3,500
	3	80	160.4	4,728	17.1	3,500
	4	80	174.0	4,864	17.6	3,500
	5	80	116.1	4,004	14.5	8,800

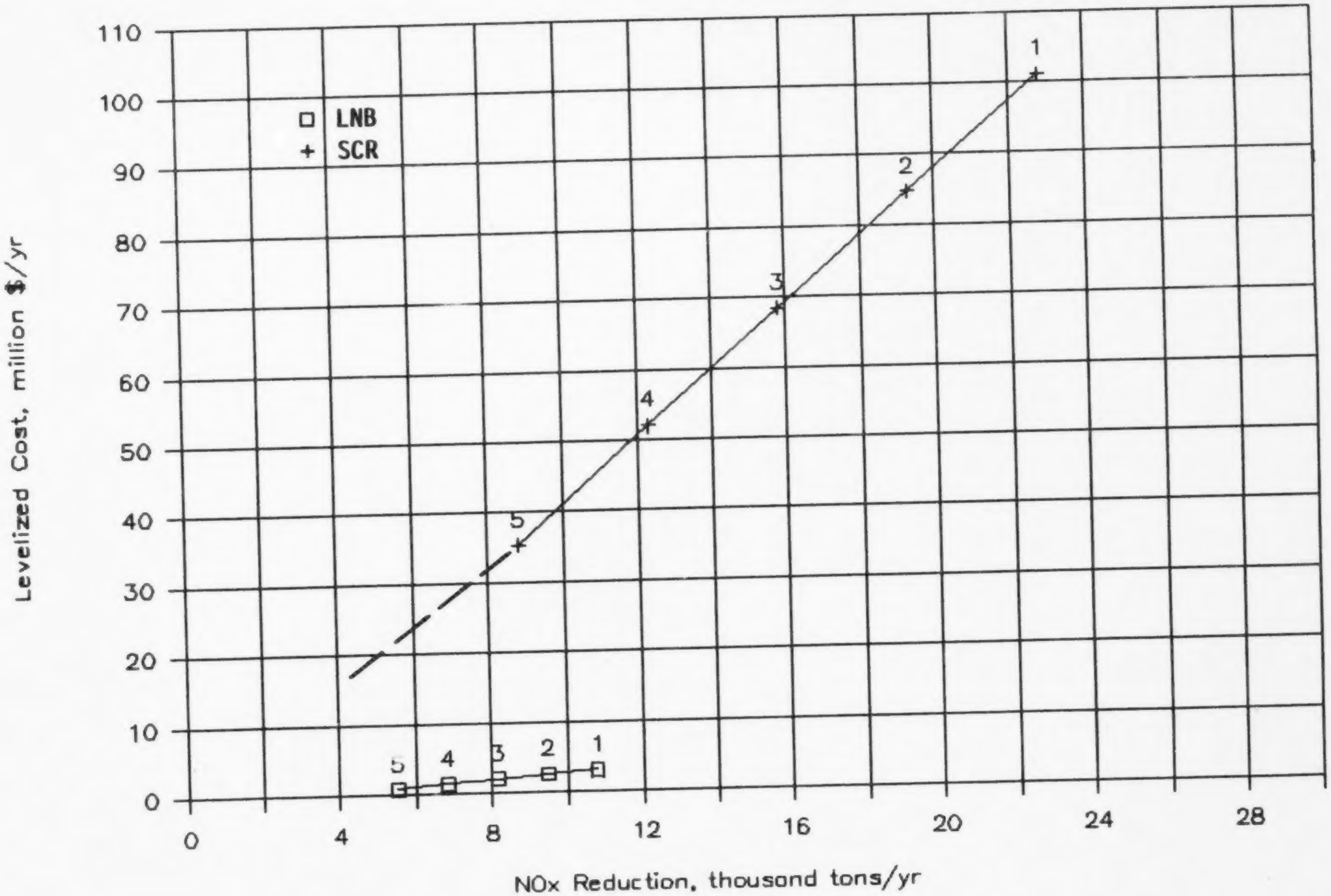

Figure 14-8. Colbert Plant NO_x controls cost versus NO_x reduction.